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***Via Electronic Submittal***

Clerk of the Board
California Air Resources Board
1001 I. Street
Sacramento, CA 95814

Re: Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Honorable Members of the California Air Resources Board:

This firm represents the Leadership Counsel for Justice and Accountability ("Leadership Counsel") in matters relating to the California Air Resources Board's ("CARB") Proposed Amendments to the Low Carbon Fuel Standard Regulation ("Proposed Amendments" or "Project"). Central Valley Defenders of Clean Water & Air, Animal Legal Defense Fund, and Food & Water Watch have informed us that they also join in this letter. CARB's adoption of the Proposed Amendments is subject to the California Environmental Quality Act ("CEQA").[1] CARB's Draft Environmental Impact Analysis ("Draft EIA") must therefore: evaluate all reasonably foreseeable impacts of the Proposed Amendments in sufficient detail; adopt all feasible mitigation measures to lessen the severity of the Proposed Amendments' environmental impacts; and consider all feasible alternatives that would achieve the goals of the Proposed Amendments while lessening the severity of the Proposed Amendments' environmental impacts. Public Res. Code §§ 21002.1; 21100. The Draft EIA fails to comply with each of these obligations.

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[1] CARB acts pursuant to a certified regulatory program which exempts the agency from preparing an Environmental Impact Report ("EIR") because the environmental analysis CARB is required to undertake is deemed the functional equivalent of an EIR. 17 Cal. Code. Regs. §§ 60000-60007; *POET, LLC v. State Air Resources Bd.* (2013) 218 Cal.App.4th 681, 710 CARB's actions are subject to all other applicable provisions of CEQA. 14 Cal. Code Regs. § 15250; *POET, LLC*, 218 Cal.App.4th at 710.

As discussed in more detail below, the Proposed Amendments will increase the already significant incentive concentrated animal feeding operations ("factory farms") have to create more Low Carbon Fuel Standard-eligible fuels and expand their operations to increase fuel production. Despite this inevitable effect of the Proposed Amendments, CARB's Draft EIA fails to mention—let alone analyze—the environmental impacts associated with factory farm expansions or anaerobic digestion-related fuel production. The Draft EIA acknowledges that the installation of anaerobic digesters, which are necessary to generate LCF-eligible fuel from manure methane emissions, will have significant environmental impacts. However, the Draft EIA fails to adequately discuss and analyze these impacts, which include impacts to air quality and water quality and adverse public health impacts on communities living in close proximity to factory farms.

In addition, the Draft EIA fails to propose adequate mitigation measures to address the project's impacts and fails to adequately analyze alternatives to the project. These inadequacies require that the Draft EIA be revised and recirculated so that the public and decision-makers are provided with a proper analysis of the project's significant environmental impacts and feasible mitigation for those impacts. See CEQA Guidelines § 15002(a)(1) (listing as one of the "basic purposes" of CEQA to "[i]nform governmental decision makers and the public about the potential, significant environmental effects of proposed activities").

This letter is submitted along with comments prepared by: Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa, Attachment A ("Secchi Comments"); and Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise ("SWAPE"), Attachment B.

## I. The Proposed Amendments incentivize factory far expansion and the installation of anaerobic digesters.

The Proposed Amendments will greatly increase the incentive that already exists under the Low Carbon Fuel Standard ("LCFS") for factory farm expansion and digester installation.

This is evidenced in the stated Project objectives, which specify the following objectives:

- Increase credit prices by increasing the carbon intensity benchmarks (Objectives 1-4, Draft EIA at 13)
- Incentivize more digesters to achieve the Senate Bill 1383, Senate Bill 32, and Assembly Bill 1279 GHG reduction targets (Objective 5, Draft EIA at 13).

- Use the LCFS to build out and then transition biomethane infrastructure from supplying transportation fuels to supplying hydrogen fuels for stationary sources (Objective 5, Draft EIA at 13).

Therefore, CARB has designed the Proposed Amendments to increase carbon intensity targets, which in turn, will increase demand for credits and increase credit prices. Currently, biomethane accounts for approximately 20 percent of credits generated but only 1 percent of energy used for transportation.[2] The quantity and growth of biomethane credits in the LCFS has contributed to a glut of credits at low prices and diminished incentive for biogas investors to expand their investments.[3] The Proposed Amendments would increase the value of LCFS credits and incentivize investors to build more digesters and generate more credits. The Proposed Amendments incentivize fuel production practices that will, in fact, increase GHG emissions and result in significant environmental impacts.

The Proposed Amendments include three distinct changes to the LCFS that will increase the incentives factory farms have to expand their operations and install anaerobic digesters: (1) strengthening the carbon intensity benchmark, thereby increasing the price of credits for eligible fuel pathways, including electricity, natural gas, and hydrogen generated from factory farm manure methane emissions; (2) limiting biomethane pathways eligible for LCFS credits with deliverability requirements, which will also increase the price of credits for eligible fuel pathways; and (3) restricting new compressed natural gas and hydrogen fuel pathways that qualify for 35 years of avoided methane crediting to those that CARB certifies or that break ground by December 31, 2029.

By strengthening the carbon intensity benchmark from a 20% reduction in carbon intensity by 2030 to 30% by 2030 and establishing a new 90% carbon intensity reduction benchmark by 2045, CARB will increase demand for LCFS credits in the near-term, especially with the “step down” in 2025.[4] The intended and inevitable effect of this change will be to increase the demand of LCFS credits available for purchase, thereby increasing credit prices. Thus, those fuel pathways that qualify for credits after the amendments go into effect—including electricity, natural gas, and hydrogen derived from

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[2] Aaron Smith, 2024.01.22 article https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy attached as Attachment C.
[3] Id.
[4] CARB Staff Report: Initial Statement of Reasons, at 22-26 (December 19, 2023) (“ISOR”).

factory farm manure—will receive more money per credit sold. The Proposed Amendments will therefore incentivize factory farms to increase their herds to maximize manure methane production (credit generation). This proposed change will also provide incentives for the installation of digesters at factory farms, and thus result in GHG and air pollutant emissions.

Additionally, the amendments include new deliverability requirements that will limit the biomethane eligible for LCFS crediting to biomethane "carried through common carrier pipelines that physically flow within California or toward end use in California."[5] Currently, all factory farms across the nation can qualify for LCFS credits on the same basis as factory farms in California. As with the carbon intensity benchmark change, these deliverability requirements will further limit the supply of LCFS credits, thereby increasing the amount of money eligible fuel producers receive per credit. Also, by limiting eligibility to those factory farms that have a connection to California, these deliverability requirements will further incentivize factory farm expansion specifically in California along with the installation of digesters at livestock facilities in California.

Lastly, the Proposed Amendments draw a bright line between factory farm fuel pathways that are certified before, and after, January 1, 2030, with respect to avoided methane crediting.[6] If a factory farm fuel pathway is certified before January 1, 2030, that pathway is eligible to be renewed for up to three consecutive 10-year crediting periods. However, fuel pathways for bio-CNG, bio-LNG, and bio L-CNG from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2040. Similarly, fuel pathways for hydrogen from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2045. The Proposed Amendments therefore provide a significant incentive for factory farms to expand their herds and install digesters before December 31, 2029.

The Proposed Amendments' incentives to expand CAFO herds and install polluting anaerobic digesters by increasing the monetization of manure methane will have significant impacts on the environment which the Draft EIA fails to adequately analyze and fails to require feasible mitigation or project alternative, as described below.

[5] ISOR, at 30-31.
[6] ISOR, at 31.

## II. The Draft EIA's Environmental Impacts analysis violates CEQA.

### A. The Draft EIA fails to analyze the Proposed Amendments' environmental impacts.

#### 1. Expansion of factory farm herds is a reasonable expected result in response to the Proposed Amendments.

CEQA requires lead agencies to analyze all reasonably foreseeable environmental impacts caused by a project they are proposing to approve. *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 396-98; *Ebbets Pass Forest Watch v. Cal. Dept. of Forestry & Fire Protection* (2008) 43 Cal.4th 936, 954-55. A public agency can only omit analysis of its project's impact if it is "speculative." *Santa Rita Union School District v. City of Salinas* (2023) 94 Cal.App.5th 298, 334-36. An agency's conclusion that a particular environmental impact is too speculative to be adequately analyzed must be supported by substantial evidence. *Id* at 335. To support such a conclusion, the CEQA Guidelines require lead agencies to conduct a "thorough investigation" and "note its conclusion" that the impact is too speculative to be considered. 14 Cal. Code Regs. § 15145; *County of Butte v. Dept. of Water Resources* (2023) 90 Cal.App.5th 147, 161; *Citizens' Committee to Complete the Refuge v. City of Newark* (2021) 74 Cal.App.5th 460, 479.

The Draft EIA's analysis is "based on reasonably foreseeable compliance responses that are based on a set of reasonable assumptions" and purportedly "includes actions that could likely occur under a broad range of the potential scenarios."[7] As explained in Section I, *supra*, the Proposed Amendments include three distinct changes that increase factory farms' incentive to generate more LCFS-eligible fuel by expanding existing herds and installing digesters. The Draft EIA considers the installation of anaerobic digesters a reasonable compliance response because the Proposed Amendments would "incentivize the collection and use of biomethane gas from dairies."[8]

The same elements of the Proposed Amendments that incentivize collecting existing biomethane at factory farms also incentivize increasing the volume of biomethane at factory farms. This incentive to produce more methane necessarily includes expanding factory farm herds to generate more manure. However, the Draft EIA ignores this potential impact entirely. The Draft EIA fails to provide any evidence, let

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[7] ISOR, at 39.
[8] Draft EIA, at 64.

alone substantial evidence, supporting its omission of factory farm expansion as a reasonable compliance response.

As explained in Dr. Secchi's comments, the analysis of Project-related impacts related to resulting factory farm expansion fails for two reasons. First, the "ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California."[9] Without such data, the Draft EIA has no evidence to support an assumption that the use of digesters at factory farms results in a reduction of methane emissions overall.

Second, the evidence demonstrates that since the adoption of the low carbon fuel standard and Federal subsidy programs encouraging use of digesters, factory farms have expanded both inside and outside of California.[10] Dr. Secchi posits that, in reality, the incentives created by the Proposed Amendments are likely to result in significant expansion of factory farms that will, in turn, increase the amount of methane produced.[11] Recent deregulation of biodigesters in Iowa is correlated with dairy expansions in that state.[12] As explained above, by increasing the carbon intensity benchmark and the value of credits, the Proposed Amendments will incentivize increased expansion and concentration of dairy operations leading to increased adverse environmental impacts (as discussed further below). The aforementioned is a reasonably foreseeable compliance response that is not accounted for in the ISOR or the Draft EIA.

Recent data from the USDA Ag Census further demonstrates that during the period that CARB has implemented its avoided methane crediting policy (since the 2018 LCFS amendments), the number of milk cows at large, California dairies have increased while the number of milk cows at smaller dairies have decreased, showing that the California dairy herd is consolidating into larger dairies that produce and store sufficient quantities of manure to finance and generate revenues from captured methane. The data show that for dairies with 2,500 or more milk cows, the milk cow herd increased from 808,503 milk cows in 2017 to 1,025,716 milk cows in 2022, or an increase of 28.6 percent. In contrast, the data show that for dairies with less than 1,000 cows, the milk cow herd *decreased* from 303,746 milk cows in 2017 to 144,472 milk cows in 2022, or a

[9] Attachment A, Secchi Comments, at 1.
[10] Id. at 5 and 6.
[11] Id.
[12] Id. at 3.

decrease of 52.4 percent.[13] While correlation does not establish causation, the data strongly suggest that the LCFS has had a substantial effect on the increase in milk cows at the largest dairies which are most likely to install digesters and monetize their manure.[14]

### 2. The Draft EIA fails to adequately analyze nitrogen-based emissions from digesters that contribute to PM2.5 nonattainment and climate change.

Having failed to properly analyze the foreseeable expansion of factory farms as a result of the Project, the Draft EIA fails to analyze the Project's related impacts. It is well-established that "industrial dairies in the San Joaquin Valley are a major source of local air and water pollution, nuisance odors, groundwater overdraft, and greenhouse gas emissions."[15] Specifically, dairies are the largest source of volatile organic compounds, in the San Joaquin Valley. Oxides of nitrogen result from combustion of fuels, including biogas fuels from anaerobic digesters. Volatile organic compounds and NOx are precursors to ozone formation, which can cause a variety of respiratory illnesses, especially in children and for people who have asthma.[16] Factory farms and the resulting digestate are also a significant source of ammonia, which impacts nearby residents as a toxic gas and also reacts to form ammonium nitrate, a form of fine particulate matter for which the EPA has classified the valley as nonattainment with the federal health-based National Ambient Air Quality Standard.[17]

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[13] The data also show that for dairies with more than 1,000 cows, the milk cow herd increased from 1,446,583 milk cows in 2017 to 1,543,730 milk cows in 2022, an increase of 6.9 percent.

[14] U.S. Department of Agriculture Census, attached as Attachment D.

[15] *See*, Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023, Attached as Attachment E.

[16] U.S. Environmental Protection Agency, "Health Effects of Ozone Pollution", attached as Attachment F and available at https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.

[17] *See* 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard), attached as Attachment G.

In addition, contaminated runoff can result in water pollution in both surface and ground water; the intensive water use required by factory farms results in overdraft of groundwater supplies; and caustic ammonia emissions can result in illness and odors. As discussed below, the Draft EIA's failure to analyze the impacts of the Proposed Amendments, both resulting in significant expansion of factory farms and due to increased use of digesters, implicates the EIA's analysis of all of the aforementioned environmental impacts. Even where the Draft EIA did purport to evaluate impacts, the analysis is perfunctory.

(a) Ammonia Emissions

Ammonia, a toxic, odorous gas, causes respiratory issues; irritation to the throat, lungs, and eyes; and lung damage if exposure to elevated ammonia levels is prolonged.[18] In addition to the health risks imposed by increased local emissions, ammonia also reacts with nitrogen oxides (e.g., NOx) in winter and contributes to the formation of ammonium nitrate, a fine particulate matter ("PM2.5").[19] In the United States, ammonia from agriculture accounts for the formation of almost one third of $PM_{2.5}$.[20] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[21] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory at best.

(b) Greenhouse Gases

The Draft EIA analysis omits a full accounting of greenhouse gas emissions resulting from both a foreseeable expansion of factory farms and increased use of digesters.[22] For example, as the Rosenfeld Comments explain, during biogas combustion in the anaerobic digestion process, ammonia is oxidized into nitrous oxides. Furthermore,

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[18] Attachment B, Rosenfeld comments, at 2.
[19] Johns Hopkins Center for a Livable Future comments on LCFS Amendments dated February 20, 2024.
[20] Id.
[21] USEPA, "Health and Environmental Effects of Particulate Matter", attached as Attachment H and available at https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[22] Attachment A, Secchi Comments, at 6.

digestate solids emit significant nitrous oxide emissions that negate methane captured by the digester. According to the EPA, nitrous oxide ("N2O") has a Global Warming Potential that is 273 times that of carbon dioxide ("CO2") for a 100-year timescale.[23] Therefore, N2O emitted today remains in the atmosphere for more than 100 years, on average.[24] Yet, the Draft EIA omits any evaluation impacts from Project-related increases of N2O.

In another example, NOx emissions react with volatile organic compounds in the presence of sunlight to form ozone, which also contributes to climate change. Ozone (O3) is the third most important anthropogenic greenhouse gas after carbon dioxide (CO2) and methane.[25] NOx also reacts with ammonia to form ammonium nitrate, a form of PM2.5. The San Joaquin Valley of California, where most factory farms and biodigesters are located, is a nonattainment area for both ozone and PM2.5National Ambient Air Quality Standards. However, the Draft EIA provides only a cursory—and internally inconsistent—discussion of the potential impacts related to ozone and PM2.5 formation. On the one hand, the Draft EIA states the Proposed Amendments "*could* result in an overall decrease in long-term operational NOx and PM2.5 emissions…in all state-designated ozone non-attainment areas from 2024 through 2046," (emphasis added) with a corresponding reduction in health impacts.[26] But the Draft EIA then pivots to conclude that long-term impacts from NOx and PM 2.5 emissions "could be potentially significant and unavoidable."[27]

The Draft EIA's conclusion that the Proposed Amendments could reduce NOx and PM2.5 emissions fails to account for emissions resulting both from the increased use of digesters and the expansion of factory farms. To the extent the Draft EIA makes any attempt to acknowledge the potentially significant impacts of increased NOx and PM2.5, it does not provide any of the information required by CEQA to explain the extent and severity of these impacts. The Draft EIA's failure to provide meaningful information about the significance of these impacts violates CEQA. *Cleveland Nat'l Forest Foundation v. San Diego Assn. of Governments* (2017) 3 Cal.5th 497, 514 ("an EIR's designation of a particular adverse environmental effect as 'significant' does not excuse

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[23] U.S. EPA, Understanding Global Warming Potentials", attached as Attachment I and available at
[24] Id.
[25] Aura Science: Greenhouse effect of tropospheric ozone, NASA, attached as Attachment J and available at https://aura.gsfc.nasa.gov/science/feature-20110403.html
[26] Draft EIA, at 57.
[27] Draft EIA, at 62.

the EIR's failure to reasonably describe the nature and magnitude of the adverse effect"); *Berkeley Keep Jets Over the Bay Com. v. Board of Port Cmrs.* (2001) 91 Cal.App.4th 1344, 1371 ("simply labeling the effect 'significant' without accompanying analysis of the project's impacts … is inadequate to meet the environmental assessment requirements of CEQA").

### 3. The Draft EIA Fails to Adequately Analyze NOx emissions from Flaring.

The Draft EIA refers to the air quality analysis in the Standard Regulatory Impact Assessment ("SRIA") as the basis for its estimates of criteria pollutants.[28] In the SRIA, CARB estimated emissions from flaring at digesters. The Draft EIA states that "[S]taff assumed that about 10% of methane produced is flared. Hence, flaring is the only source of local emissions used in estimating emissions from dairy biomethane."[29] Ammonia in flared biogas causes increased NOx emissions.[30] However, the SRIA only used air district emission factors for flares.[31] Thus, the EIA fails to adequately analyze NOx emissions from flaring biogas. A revised EIA should recalculate digester flare emissions using flared biogas.

### 4. The Draft EIA Fails to Adequately Analyze NOx emissions from Biomethane Electric Fuel Pathways.

In its evaluation of Project-impacts related to biomethane electric vehicle fuel pathways, the Draft EIA indicates that "[T]he LCFS modeling assumes use of fuel cells to generate this electricity, which do not rely on combustion."[32] Thus, staff calculate near zero NOx from electricity production of biomethane using an emission factor of 0.00085 tons/GWh.[33] However, this assumption underlying the analysis is questionable for multiple reasons. First, to date, CARB has certified only one biomethane electric vehicle fuel pathway that relies on Bloom fuel cells at a dairy to produce electricity, and that is at

[28] Draft EIA, at 58.
[29] SRIA, Appendix C-1 at B-2 Table 49.
[30] Attachment B, Rosenfeld Comments at 4.
[31] SRIA, Appendix C-1 at B-2.
[32] Draft EIA, at 27; SRIA, Appendix C-1 at B-3, (citing a dead link Bloom Energy (2002). *The Bloom Energy Server 5 Data Sheet*. https://www.bloomenergy.com/wp-content/uploads/es5-300kw-datasheet-2022.pdf)] .
[33] Id.

Bar 20, one of the largest dairies in California. By contrast, CARB has certified 19 biomethane electric vehicle fuel pathways that rely on internal combustion engines[34] .

Second, Bloom fuel cells are more expensive to purchase and maintain than internal combustion engines, and the San Joaquin Valley Unified Air Pollution Control District has declined to find that fuel cells are cost-effective and thus Best Available Control Technology ("BACT"). Instead, the District has issued Authority to Construct Permits and found that internal combustion engines represented BACT. Therefore, CARB lacks substantial evidence to support its unfounded assumption Bloom fuel cells will be used for electric vehicle fuel pathways. And while Bar 20 has permits for and operates fuel cells, there is no record on the Air District public notice log of *any* BACT determination for fuel cells at Bar 20.[35]

Furthermore, the most recent internal combustion engine Authority To Construct Permit from the San Joaquin Valley Air District found that fuel cells were not cost-effective and not BACT. Instead, the Air District required internal combustion engines as BACT.[36] This approach is inconsistent – on the one hand, the Air District does not consider fuel cells as BACTs or cost effective and does not require fuel cells as BACT; on the other hand, CARB's analysis of impacts from digester projects that generate electric vehicle fuel contends that all such fuel pathways will rely on fuel cells to emit near-zero NOx.

NOx emissions from digester-related internal combustion engine used for electric vehicle fuel pathways are significant. For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[37] And this project, as permitted by the Air District with required internal combustion engines, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5,

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[34] CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024, attached as Attachment K.
[35] SJVAPCD Bar 20 Bloom Energy Permits, attached as Attachment L.
[36] *See* Attachment M - 2020.04.20 Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy at 13, Appendix C.
[37] SJVAPCD, Notice of Preliminary Decision – Authority to Construct (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf, attached as Attachment N; CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 (certified TBD), attached as Attachment O and available at https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.

and 3.18 tons/year of VOC *after* the imposition of BACTs as required by the State Implementation Plan.[38] Compared to a natural gas combined cycle power plant in Avenal, also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[39] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted. This facility, and others like it with internal combustion engines, emit significant levels of NOx even after Clean Air Act-required controls.[40] Therefore, the Draft EIA wrongfully omitted analysis NOx emissions from these facilities and fuel pathways.[41]

In summary, given that (a) the Proposed Amendments increase carbon intensity benchmarks, and thus credit prices, and will incentivize more pathways for electricity from internal combustion engines, (b) CARB does not require fuel cells as mitigation, and (c) the San Joaquin Valley Unified Air Pollution Control District does not consider fuel cells as BACT, it is reasonably foreseeable that more digesters with IC engines will apply for such pathway certifications. For these reasons, the Draft EIA must be revised to correct this error and to evaluate NOx impacts from biomethane electric vehicle fuel pathways that rely on IC engines.

**5. The Draft EIA Fails to Adequately Analyze NOx emissions after 2039.**

The Draft EIA fails to analyze NOx emissions from biomethane fuel pathways after 2039, despite authorizing crediting for biomethane fuel pathways well beyond 2039. The Draft EIA's PM2.5 and NOx emissions analysis explicitly relied on the Standardized Regulatory Impact Assessment ("SRIA"), including Tables 47-59.[42] Table 47 of the SRIA assumes no hydrogen or electricity will be produced from dairy biomethane after 2039.[43] However, as discussed in Section I, the Proposed Amendments explicitly

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[38] SJVAPCD, *supra* note 137, at 14.
[39] SJVAPCD, Notice of Final Determination of Compliance, (December 17, 2010) Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01), attached as Attachment P.
[40] Id.; Attachment Q Comparison of Digester vs. Avenal; and Rosenfeld Comments at _.
[41] Johns Hopkins, Center for a Livable Future comments LCFS Amendments; Petition for Reconsideration at 28-30, attached as Attachment R.
[42] Draft EIA, at 58.
[43] CARB Staff Report: Initial Statement of Reasons for Proposed Amendments to the Low Carbon Fuel Standards, Appendix C-1: Standardized Regulatory Impact Assessment, at B-3 (September 9, 2023) ("SRIA").

authorize CARB to certify electricity and hydrogen fuel pathways well beyond 2039. The Draft EIA's analysis of NOx emissions is grounded on an inaccurate assumption. The Draft EIA must evaluate the impacts of NOx emissions over the time period during which these emissions will occur. 14 Cal. Code Regs. § 15126 ("[a]ll phases of a project must be considered when evaluating its impact on the environment"); *Make UC a Good Neighbor v. Regents of University of California* (2023) 88 Cal.App.5th 656, 667; *In re Bay-Delta etc.* (2008) 43 Cal.4th 1143, 1169.

**6. The Draft EIA fails to adequately analyze Project-related ammonia emissions associated with digestate.**

Aside from omitting analysis of the impacts resulting from factory farm expansion and use of anaerobic digesters described above, the Draft EIA presents an incomplete analysis of the project's ammonia impacts because it fails to evaluate the impacts from production and application of substantial increases of anaerobic digestate.[44] Apart from the size of the herd, the production and application of digestate to agriculture land is much more polluting and more hazardous to public health compared to raw manure.[45] CEQA requires an analysis of these impacts.

The Draft EIA's conclusion that the Project may have significant air quality impacts—without consideration of the extent and severity of those impacts—cannot cure this deficiency. Merely stating that an impact will occur is insufficient; an EIR must also provide "information about how adverse the adverse impact will be." *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371. This information, of course, must be accurate and consist of more than mere conclusions or speculation. *Id*. The Draft EIA's analysis of air quality impacts fails to fulfill this mandate in several instances.

(a) Air pollution

Anaerobic digestate results in higher emissions in part because anaerobic digestion decomposes the waste into smaller molecules, which allows it to more easily volatilize into the atmosphere.[46] In this way, digestate results in significant releases of higher

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[44] Draft EIA at 56-62 (concludes impacts to air quality are significant); at 64-65 (concludes impacts from odor are not significant); Attachment B, Rosenfeld comments, at 2 and 3.
[45] Johns Hopkins Center for a Livable Future comments on LCFS Amendments at 2.
[46] Attachment B, Rosenfeld comments, at 3.

amounts of ammonia, a toxic gas, and NOx emissions than unprocessed manure.[47] The Draft EIA concludes that long-term operational air quality impacts related to PM2.5 and NOx would be significant and unavoidable.[48] We do not disagree that the Project's emissions would be significant. However, the DEIR fails to disclose the extent and severity of this impact.[49] A revised analysis must provide more details about the impacts and must account for increased application of digestate on agricultural land. *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371.

Furthermore, the Draft EIA's conclusion that odor impacts from ammonia emissions would not be significant is unsupported. As explained in the Rosenfeld Comments, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[50] In addition, anaerobic digestion significantly increases the amount of ammonia emissions compared to a dairy without an anaerobic digester.[51]

As discussed above, ammonia also contributes to the formation of $PM_{2.5}$ (e.g., formation of ammonium nitrate), exposure to which is linked to a variety of serious health problems).[52] CARB's own ammonia data show that ammonia contributes to PM2.5 formation.[53] Therefore, CARB must include a full evaluation of ammonia emissions.

(b) Public Health and Safety

Health and safety effects, including adverse health impacts from air pollutants, may constitute significant environmental impacts for the purposes of CEQA. See, e.g., *Sierra Club v. County of Fresno* (2018) 6 Cal.5th 502, 517-22; *Bakersfield Citizens for*

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[47] Id.
[48] Draft EIA at 62.
[49] Draft EIA at 56-62.
[50] Rosenfeld Comments at 2.
[51] *Id*. at 3-4.
[52] Johns Hopkins Center for a Livable Future comments on LCFS Amendments comments at 3; See Attachment H https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[53] 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV at 3, attached as Attachment S.

*Local Control v. City of Bakersfield* (2004) 124 Cal.App.4th 1184,1219-21. 14 CCR § 15126.2(a). Here, as discussed above, in the anaerobic digestion process substantial amounts of ammonia are produced as a byproduct.

In addition to the health risks imposed by increased local emissions, emissions and impacts on nearby communities, ammonia also contributes to the formation of $PM_{2.5}$.[54] In the United States, ammonia from agriculture accounts for the formation of almost one third of $PM_{2.5}$.[55] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[56] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory.[57] While the Draft EIA discloses that an increase in emissions of criteria pollutants associated with production of biofuels is possible, it falls short of actually evaluating the potential health impacts of these emissions.[58] Instead, once again the Draft EIA concludes that impacts would be significant, but then fails to describe the severity of those impacts.

Harmful emissions from expanded use of anaerobic digesters disproportionately affect communities in close proximity to dairies, which are often comprised of lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

(c) Impacts Outside of California

The Draft EIA fails to analyze the Proposed Amendments' impacts outside of California. CEQA requires public agencies to analyze the potentially significant impacts of a proposed project that may occur in "the area which will be affected by [the] proposed project." 14 Cal. Code. Regs. § 15360; Public. Res. Code § 21060.5. CARB itself acknowledged its obligation to analyze out-of-state impacts in conducting its CEQA

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[54] Id.
[55] Id.
[56] See Attachment H; https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing.
[57] Draft EIA, at 61 and 62.
[58] Id.

review for the Renewable Electricity Standard in 2010.[59] Factory farms across the nation are eligible for LCFS credits, and are thus incentivized by the Proposed Amendments to install anaerobic digesters and expand existing herds, just as in-state factory farms are. The Proposed Amendments will therefore have adverse environmental impacts out-of-state. CARB's refusal to analyze such impacts is clear legal error.

**7. The Draft EIA fails to adequately analyze Project-related discharges to groundwater associated with digestate.**

The Draft EIA's analysis of increased digestate on groundwater is equally flawed. As explained in the Rosenfeld Comments, anaerobic digestion breaks down waste into a digestate of smaller molecules that makes digestate more susceptible to leaching into the groundwater.[60] Anaerobic digestion also leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate.[61]

"[N]itrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater."[62] Nitrate contamination in drinking water and food can lead to severe illness in infants, such as the onset of blue baby syndrome, also known as methemoglobinemia.[63] Yet, the Draft EIA fails to include any analysis of these potential impacts.

Although the Draft EIA concludes that the Project's long-term operational impacts to water quality are significant and unavoidable, the document lacks a thorough analysis of these impacts. As the Rosenfeld Comments explain, increased amounts of digestate have the potential to result in groundwater nitrate contamination, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[64] These impacts to water quality and public health must be evaluated in a revised EIA.

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[59] California Air Resources Board, Functional Equivalent Document for the Renewable Electricity Standard, at E-77, E-82, E-83, E-105, E-107, E-108 (June 2010), attached as Attachment T and available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf.
[60] Attachment B at 5.
[61] Id.
[62] Attachment B at 5 and 6.
[63] Id.
[64] Id. at 7.

In summary, the Draft EIA fails to grapple with an analysis of all of the foreseeable, significant, direct and indirect environmental impacts of implementing the Proposed Amendments. As discussed above and in several comment letters from other stakeholders, these impacts include, but are not limited significant air quality, climate change, water quality, and public health impacts. Furthermore, as discussed below, the Draft EIA fails to identify feasible mitigation measures to minimize acknowledged significant impacts resulting from the project. A revised EIA must correct these deficiencies in order for the public and decision-makers to fully understand the Project's impacts.

**III. The Draft EIA fails to identify any enforceable mitigation measures to lessen the severity of the Proposed Amendments' significant impacts.**

If, as here, a lead agency determines its project will have one or more significant environmental effects, CEQA requires that agency to adopt all feasible mitigation measures to reduce the severity of those impacts. Public. Res. Code § 21002; *Sacramento Old City Assn. v. City Council* (1991) 229 Cal.App.3d 1011, 1027; *POET, LLC*, 218 Cal.App.4th at 734-35. Mitigation can take many forms, including avoiding the impact altogether by not taking a certain action or parts of an action and minimizing impacts by limiting the degree or magnitude of the action and its implementation. 14 Cal. Code Regs., § 15370. Mitigation measures are only legally valid if they are fully enforceable. Public Res. Code § 21081.6(b); *Assn. of Irritated Residents v. Kern County Bd of Supervisors* (2017) 17 Cal.App.5th 708, 752.

The Draft EIA's approach to mitigation measures is woefully deficient. CARB has not proposed *any* enforceable mitigation measures to be incorporated as part of the Proposed Amendments. The Draft EIA's reasoning for doing so is based on a fundamental legal error. Because CARB has no authority over the projects and actions that will be undertaken in response to the Proposed Amendments, the Draft EIA asserts that CARB has no obligation to incorporate feasible mitigation measures into the Proposed Amendments themselves. CARB does have jurisdiction over the Proposed Amendments, and it must include measures that will reduce or eliminate the reasonable foreseeable impacts of the Amendments. 14 Cal. Code Regs. § 15126.4.

The Draft EIA's illogical reasoning is compounded by its unsupported assumption that the projects it identifies as reasonably compliance responses will be subject to future CEQA review. Factory farm expansions and digester installations are commonly considered exempt from CEQA review by the local agencies in Central Valley that routinely approve such projects. The Leadership Counsel proposes numerous feasible mitigation measures CARB can, and must, incorporate into the Proposed Amendments to lessen the severity of its significant impacts associated with digester installation and factory farm expansion.

### 1. The Draft EIA's approach to mitigation measures is legally erroneous.

CARB has not proposed *any* enforceable mitigation measures, despite the Draft EIA concluding that the Proposed Amendments will have numerous significant environmental impacts. According to the Draft EIA, CARB—one of the most powerful regulators in the State—has no ability or authority to mitigate the impacts associated with the Proposed Amendments. In attempting to off-load its obligation to impose feasible mitigation measures, CARB confuses the project before it—the Proposed Amendments—with the projects (e.g. anaerobic digesters, factory farm expansions) that will be undertaken *as a result* of the Proposed Amendments. Because CARB does not have authority over these projects, the Draft EIA asserts CARB has no ability to incorporate feasible mitigation measures within the Proposed Amendments.

However, CEQA requires CARB to determine whether changes or additions can be made to the *Proposed Amendments themselves* that will reduce the severity of their significant environmental impacts. 14 Cal. Code Regs. § 15126.4(a)(2) ("[i]n the case of the adoption of a plan, policy, regulation, or other public project, mitigation measures can be incorporated into the plan, policy, regulation, or project design"). CARB clearly has the authority to make changes or additions to its own Proposed Amendments, which will lessen the severity of their environmental impacts. Its failure to even consider doing so constitutes grave legal error.

### 2. CARB's EIA process is likely the last opportunity for environmental review and mitigation of the impacts of factory farm expansion and digester installation.

CARB's faulty reasoning is compounded by its unsupported assumption that the projects which will be undertaken as a result of the Proposed Amendments will be subject to future CEQA review and, thus, the obligation to mitigate significant impacts. However, in the Central Valley, where factory farms are predominately located, the installation of anaerobic digesters and the expansion of factory farms are commonly considered by local agencies to be exempt from CEQA review on the grounds that the projects are ministerial or qualify for a categorical exemption. Therefore, with respect to these projects, the Draft EIA process is likely the last stop for both detailed environmental review and the imposition of meaningful mitigation measures.

For example, Kings County has adopted local guidelines that inform its implementation of CEQA.[65] Included in these guidelines are a list of categories of projects that are exempt from CEQA review because they are subject to ministerial review. These ministerial projects include "Site Plan Reviews." In 2023 alone, Kings County approved two anaerobic digester projects, exempting them from CEQA review on the grounds they were subject to ministerial review.[66] Kings County thus had no obligation under CEQA to analyze and mitigate the adverse impacts associated with either of these projects.

Other jurisdictions have exempted digester projects from CEQA review—and the obligation to mitigate significant impacts—on the grounds that these projects qualify for a Categorical Exemption. For example, Tulare County issued a Notice of Exemption in 2020 for a pipeline construction project intended to transport dairy biogas on the grounds the project qualified for the Class 1 (minor alterations to existing facilities) and Class 3 (new construction of small structures) Categorical Exemptions.[67] Tulare County also filed a Notice of Exemption to expand an existing biogas pipeline to connect an additional dairy digester to existing infrastructure. Other jurisdictions where similar projects have been exempted from CEQA review recently include Merced, Stanislaus, and Kern.

Tulare County also filed multiple Notices of Exemption in 2022 for factory farm herd consolidation projects, including a project that increased an existing herd size by

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[65] Kings County, *Local Guidelines for the Implementation of CEQA*, (January 5, 2016), attached as Attachment U and available at https://www.countyofkings.com/home/showpublisheddocument/12485/635919879294330000.

[66] Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project (December 7, 2023), attached as Attachment V and available at https://files.ceqanet.opr.ca.gov/293555-1/attachment/CDzMvjy1XpNztMTMZYB397RSlELw_rWgq8tiJxKcc3SF7-nLFEgELbQwM06hiwOeTZEiJUhU6gqHLBNx0; Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project (May 15, 2023), attached as Attachment W and available at https://files.ceqanet.opr.ca.gov/287881-1/attachment/q5K_P65aU7RUja-BYGe9-uDeE-Fz0Az_DAbus84Q28vqdXyG1cceIHq937esHc4jb7WmtPLcv9qGvzOn0.

[67] Tulare County Notice of Exemption for Tulare Biogas Gathering Line (August 18, 2020), attached as Attachment X and available at https://files.ceqanet.opr.ca.gov/264014-2/attachment/ZQ976ZUWit1klndpB1s5MYMKZJQBpo6c-8VIweVKasCVOsmAyGVogK05MqqmSLuQk994sssNab-A3-7Q0.

almost 3,000 animal units.[68] Kings County filed a Notice of Exemption for a project that expanded the herd size of an existing calf ranch in 2023 on the grounds that the underlying approval was ministerial.

CARB's attempt to justify its refusal to adopt any enforceable mitigation measures on the grounds that the projects incentivized by the Proposed Amendments will be subject to future CEQA review fails. CARB's discretionary approval of the Proposed Amendments is likely the last chance to rigorously analyze and mitigate the significant impacts associated with many future factory farm expansions and digester development projects. CARB must use its authority as the regulatory agency tasked with crafting the LCFS to ensure all identified significant impacts are mitigated to the extent feasible.

**3. CARB must adopt feasible mitigation measures that will lessen the severity of the Proposed Amendments' impacts on factory farm expansion and digester installation.**

CEQA explicitly acknowledges that feasible mitigation measures can include changes that are incorporated into the regulation itself. 14 Cal. Code Regs. § 15126.4(a)(2). Each of the following mitigation measures is feasible and within CARB's authority to incorporate within the Proposed Amendments; CARB's failure to do so would constitute a clear violation of CEQA:

- Limit the generation of credits for fuel pathway holders for biogas derived from livestock manure to the volume of feedstock at each associated dairy or livestock operation on January 1, 2017, or on the date the pathway was certified, whichever is earlier.

- Restrict the generation of credits for fuel pathway holders for biogas derived from livestock manure located in Disadvantaged Communities as designation by the Office of Environmental Health Hazard Assessment pursuant to Senate Bull 535.[69]

- When calculating the carbon intensity of fuel derived from livestock manure, include all emissions of greenhouse gases generated from the production of the

[68] Cows, pigs, and other animals raised in factory farms and dairies are not "units," but are sentient beings, each of which has its own unique personality.
[69] An interactive map delineating the Disadvantaged Communities throughout the State is available at https://oehha.ca.gov/calenviroscreen/sb535. A copy of the state-wide map is attached as Attachment Y.

fuel and all emissions of greenhouse gases generated from the production of the feedstock. Update the carbon intensity of each pathway for fuel derived from livestock manure after making this calculation. These emissions include, but are not limited to,

  - o Enteric emissions;
  - o Emissions from production and storage of feed, transport of feedstock, or fuel;
  - o Emissions resulting from digestate handling, composting, or treatment; and
  - o Emissions resulting from land application of manure or digestate.

- Disapprove any application for a fuel pathway that includes the use of biogas derived from livestock manure which does not provide all information and calculations used to determine carbon intensity, including but not limited to:
  - o Herd size;
  - o Volume of feedstock produced or used;
  - o Volume of biogas produced.
- Make publicly available on CARB's website all information and calculations used to determine carbon intensity.

**IV. The Draft EIA fails to analyze all reasonable alternatives by which the State can achieve its methane reduction goals.**

As a preliminary matter, the Draft EIA's failure to disclose the extent and severity of the Project's broad-ranging impacts necessarily distorts the document's analysis of Project alternatives. As a result, the alternatives are evaluated against an inaccurate representation of the Project's impacts. Proper identification and analysis of alternatives is impossible until Project impacts are fully disclosed.

CEQA requires CARB's Draft EIA to describe a range of "reasonable alternatives to the project," which would "attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effect of the project," and evaluate the "comparative merits" of the alternatives. 14 Cal. Code. Regs. § 15126.6. The discussion of mitigation and alternatives is "the core" of CEQA analysis. *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 564.

The Draft EIA's alternatives analysis presents a series of false choices, that rests on the assumption that the only method by which the State can achieve its methane emissions reduction goals is through the LCFS's indirect, incentive-based regulation. Each alternative scenario is simply a version of the LCFS with different requirements than the Proposed Amendments. The Draft EIA fails to analyze a scenario where CARB uses its regulatory authority to directly regulate methane emissions from factory farms, as required by Health & Safety Code §§ 38562.5, 39730.7(b)(1), thereby achieving the State's methane reduction goals while reducing the incentive for factory farms to expand their environmentally damaging operations.

The Draft EIA must be amended to include analysis of an alternative scenario with the following components: (1) elimination of LCFS credits for fuel derived from manure methane emissions; (2) implementation of direct regulation of factory farms to achieve the same level of methane reduction CARB currently contemplates will be achieved through the LCFS; and (3) decrease the stringency of the LCFS' carbon intensity requirement, to ensure the elimination of credits for fuel derived from manure methane emissions does not affect credit prices negatively and risk the State failing to achieve its fuel decarbonization goals.

The State Legislature has granted CARB the regulatory authority to directly regulate the major sources of methane emissions within the State, including the dairy and livestock industry, landfills, and the oil and gas system. To date, CARB has taken action to directly regulate landfills (the Landfill Methane Regulation, Cal. Code of Regs., tit. 17 §§ 95460, et seq.) and the oil and gas system (the Oil and Gas Methane Regulation, Cal. Code of Regs., tit. 17, §§ 95665-77). However, CARB has yet to directly regulate the dairy and livestock industry—the largest source of methane emissions within the State.

The State Legislature, through Senate Bill 1383, mandated that CARB adopt regulations and mandated that CARB implement such regulations beginning in January of 2024 provided that CARB make certain findings. As CARB itself has stated, the agency shall adopt regulations and has authority to implement the regulations, "provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs."[70]

CARB itself acknowledged in its 2022 Scoping Plan that direct regulation of the sources of methane emissions is integral to the State's methane emissions reduction strategy.[71] CARB's stated strategy for reducing the emissions of short-lived climate pollutants, most notably methane, is a "carrot-then-stick" approach.[72] This approach begins with the incentive-based, indirect regulations, such as the LCFS (the "carrot"), and then transitions into direct regulation, similar to those that have been promulgated for the landfill and oil and gas systems (the "stick"). The 2022 Scoping Plan ultimately recommends the carrot and stick approach for manure methane.[73] CARB acknowledged that the dairy and livestock industry must "achieve considerable methane emissions reductions to meet the 2030 target," which will "require implementation of additional methane emissions reductions strategies."[74]

Despite having the mandatory duty and authority to directly regulate methane emissions from the dairy and livestock industry, and explicitly stating that such regulation is integral to the State's emissions reduction strategy, CARB fails to analyze an alternative scenario where this direct regulatory authority is applied. The only alternatives CARB considers are those where the LCFS is the primary, if not sole, mechanism for achieving methane emissions reductions from the dairy and livestock industry. CARB has the authority to simultaneously reduce the methane emissions and adverse environmental impacts from factory farms, while not risking the State's fuel decarbonization goals. CARB's failure to consider such a scenario constitutes clear legal error.

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[70] California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, at ES-4 (March 2022), attached as Attachment Z and available at https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.
[71] California Air Resources Board, 2022 Scoping Plan, at 222-25 (2022), attached as Attachment AA and available at https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.
[72] *Id*. at 223.
[73] *Id*. at 232.
[74] CARB, Analysis of Progress Toward Achieving 2030 Methane Emissions Target, at ES-6.

## V. Conclusion

Due to the foregoing and numerous adverse environmental impacts not fully disclosed and properly analyzed in the Draft EIA, the Leadership Counsel opposes the Project as proposed. Additional alternatives and mitigation measures are essential to avoid the Project's significant adverse impacts. The Leadership Counsel respectfully urges the Air Resources Board to delay further consideration of this Project until the agency recirculates a revised Draft EIA that fully complies with CEQA and the CEQA Guidelines.

Very truly yours,

SHUTE, MIHALY & WEINBERGER LLP

Ellison Folk

**Attachments:**

Attachment A: Comments of Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa

Attachment B: Comments of Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise

Attachment C: Aaron Smith, "Cow poop is now a big part of California Fuel Policy", UC Davis, Jan. 22, 2024.

Attachment D: U.S. Department of Agriculture, 2017 Census of Agriculture – State Data, Table 17. Milk Cow Herd Size by Inventory and Sales: 2017 and Table 17. Milk Cow Herd Size by Inventory and Sales: 2022

Attachment E: Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023.

Attachment F: U.S. EPA, "Health Effects of Ozone Pollution"; https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.

Attachment G: 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard).

Attachment H: U.S. EPA, Health and Environmental Effects of Particulate Matter, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing

Attachment I: U.S. EPA, Understanding Global Warming Potentials; https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

Attachment J: Aura Science: Greenhouse effect of tropospheric ozone, NASA, https://aura.gsfc.nasa.gov/science/feature-20110403.html

Attachment K: CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024.

Attachment L: SJVAPCD Bar 20 Bloom Energy Permits

Attachment M: Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy

Attachment N: SJVAPCD, Notice of Preliminary Decision – Authority to Construct Lakeview Dairy Biogas (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf.

Attachment O: CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 Lakeview Dairy Biogas(certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf

Attachment P: Notice of Final Determination of Compliance, Avenal Power Center, at 3, 27 (Dec. 17, 2010)

Attachment Q: Digester v. Avenal Comparison

Attachment R: Excerpt from Petition for Reconsideration Of The Denial Of The Petition For Rulemaking To Exclude All Fuels Derived From Biomethane From Dairy And Swine Manure From The Low Carbon Fuel Standard Program

Attachment S: 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV.

Attachment T: Excerpts of CARB Functional Equivalent Document for Renewable Electricity Standard, June 2010.
https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf

Attachment U: Kings County, *Local Guidelines for the Implementation of CEQA*, January 5, 2016.

Attachment V: Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project, December 7, 2023.

Attachment W: Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project, May 15, 2023.

Attachment X: Tulare County Notice of Exemption for Tulare Biogas Gathering Line, August 18, 2020.

Attachment Y: OEHHA SB 535 Disadvantaged Communities Map, https://oehha.ca.gov/calenviroscreen/sb535.

Attachment Z: California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (March 2022), https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.

Attachment AA: California Air Resources Board, 2022 Scoping Plan https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

# ATTACHMENT A

**Comments on the Amendments to Low Carbon Fuel Standard**

**Silvia Secchi**

My name is Silvia Secchi and I am a professor in the Department of Geographical and Sustainability Sciences at the University of Iowa. I have a Ph.D. in economics from Iowa State University and have been studying the environmental impacts of Midwestern agriculture for over a quarter of a century, my google scholar profile shows see my record of peer reviewed publications[1]. I have reviewed the Initial Statement of Reasons of the Proposed Amendments to California's Low Carbon Fuel Standard and associated Appendices. Based on my my professional expertise as an agricultural economist, I have several concerns about CARB's failure to adequately address the potential for changes in the Standard to encourage the development of concentrated animal feeding operations, both through the establishment of new dairies and the concentration of existing operations.

First, the ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California. As a result, CARB cannot in good faith assert that the capturing of manure from CAFO is actually reducing methane emissions from dairy and/or hog operations, and that the LCFS will not result in rebound effect or Jevon's paradox: the technological improvement (in this case the biodigesters) change the behavior of consumers and producers so that the efficiency gains actually result in increased production and the net effects are not reductions but increases in resource use and – in this case – methane emissions. There is extensive evidence of this type of phenomenon in the agricultural sector[2].

CARB's lack of jurisdiction outside state borders exacerbates this problem by causing a "race to the bottom" in jurisdictions that build digesters as a way to attract new operations or allow existing operations to expand along with digester installation. Race to the bottom has been found to be a significant factor in determining location of Confined Animal Feeding Operations (CAFOs) for both dairy and hog operations[3].

Here I detail recent trends in dairy production in Iowa and the increase in biodigesters, to show that the LCFS is already having an impact. The data I present here are the result of several hours of search on the Iowa Department of Natural Resources (DNR) website. I conducted this research in the course of a project in which I am examining the effects of lax environmental regulations in the expansion of CAFOs, in particular in association with "climate smart" policies. This data is important because the EPA Agstar database[4] that experts like Prof. Aaron Smith at UC Davis have been using severely underreports the number of biodigesters compared to the Iowa DNR site. As a result, national level analyses are extremely likely to underestimate the rebound effect. This is likely to be compounded by the fact that the deployment of biodigesters and the expansion do not always occur in the same year, as evidenced in two cases reported in

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[1] https://scholar.google.com/citations?user=rXte6MIAAAAJ&hl=en&oi=ao

[2] Paul, C., Techen, A. K., Robinson, J. S., & Helming, K. (2019). Rebound effects in agricultural land and soil management: Review and analytical framework. Journal of cleaner production, 227, 1054-1067.

[3] Herath, D., Weersink, A., & Carpentier, C. L. (2005). Spatial Dynamics of the Livestock Sector in the United States: Do Environmental Regulations Matter? Journal of Agricultural and Resource Economics, 30(1), 45-68.

[4] https://www.epa.gov/agstar

Table 1. In these cases, the impacts of the biodigesters on expansion will easily be underestimated.

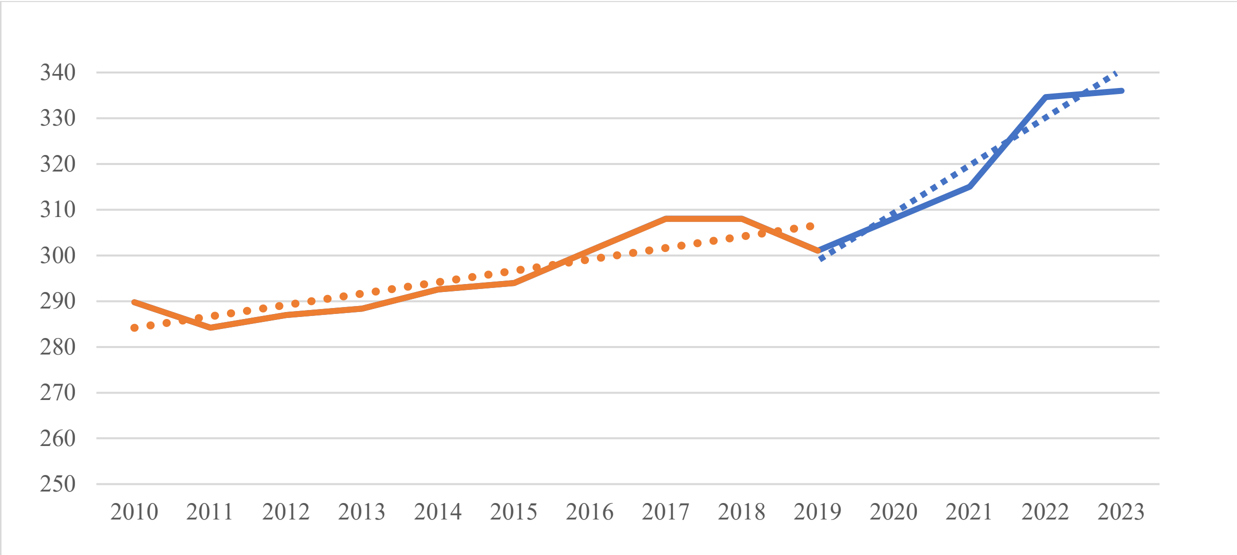
As Table 1 shows, there have been 15 digesters built in Iowa dairies since 2019. **The AgStar database only includes 4 of them.** These 15 digesters are associated with an increase of over 17,000 Animal Units (AUs). This corresponds to an increase of almost 20% in AUs. Milk production in Iowa had been growing, but it was doing so at a much slower pace before 2019 (Figure 1). Though it is not possible to formally attribute causality, it is notable that Iowa's dairy cows AUs increased by 35,000 between 2019 and 2023. **This means that a large portion of the increase in milk cows in the state is associated with biodigesters.**

Table 1 – Recent biodigesters installed in Iowa and associated capacity expansion

| | Facility location | General Location | ID | Year | Initial size (AUs) | Final size (AUs) |
|---|---|---|---|---|---|---|
| Black Soil Dairy | Granville | North West | 60565 | 2021 | 4,500 | 4,500 |
| Geno | Blairstown | East Central | 61209 | 2022 | 6,280 | 7,512 |
| Kirkman Farms | Kirkman | West Central | 64174 | 2021 | 8,500 | 11,900 |
| Legacy Dairy | Sanborn | North West | 60531 | 2022 | 3,920 | 6,160 |
| Maassen | Maurice | North West | 57177 | 2022 | 3,200 | 3,995 |
| Marshall Ridge Farms | State Center | Central | 60101 | 2020 digester 2023 expansion | 8,499 | 11,425 |
| Meadowvale Dairy North | Rock Valley | North West | 62015 | 2021 | 20,300 | 20,300 |
| Rock River Jerseys-Inwood Dairy | Doon | North West | 66387 | 2019 digester 2022 expansion | 8,499 | 14,000 |
| Roorda Dairy | Paullina | North West | 64981 | 2021 | 5,880 | 5,880 |
| Salix Farms | Salix | North West | 64623 | 2023 | 3,500 | 3,500 |
| Sioux Jerseys | Salix | North West | 62420 | 2023 | 6,300 | 6,300 |
| Van Ess Dairy | Sanborn | North West | 65143 | 2021 | 7,599 | 8,499 |
| Winding Meadows Dairy | Rock Valley | North West | 60218 | 2021 | 2,884 | 3,360 |

Source: Iowa DNR Animal Feeding Operation online application https://programs.iowadnr.gov/afoemmp/

Figure 1 – Iowa milk cow AUs (1,000s)




Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

Again, it is not possible to demonstrate unequivocally that this growth in dairy operations is directly linked to the expanded use of biodigesters. But two laws deregulating biodigesters were recently passed in Iowa. In 2019 SF 534[5] repealed the statutory requirement for rulemaking for all waste control technology facilities, including biodigesters, and in 2021, HF 522[6] allowed large dairies (over 8,500 AUs) to exceed confinement capacity if they install an anaerobic digester to treat all manure. There is a strong correlation between the deployment of biodigesters and the dairy expansions. As Table 1 shows, there were 3 such operations that expanded as they deployed biodigesters. In my professional opinion, this very strongly suggests that the increasing availability and decreasing regulation of biodigesters is contributing to dairy expansion and concentration.

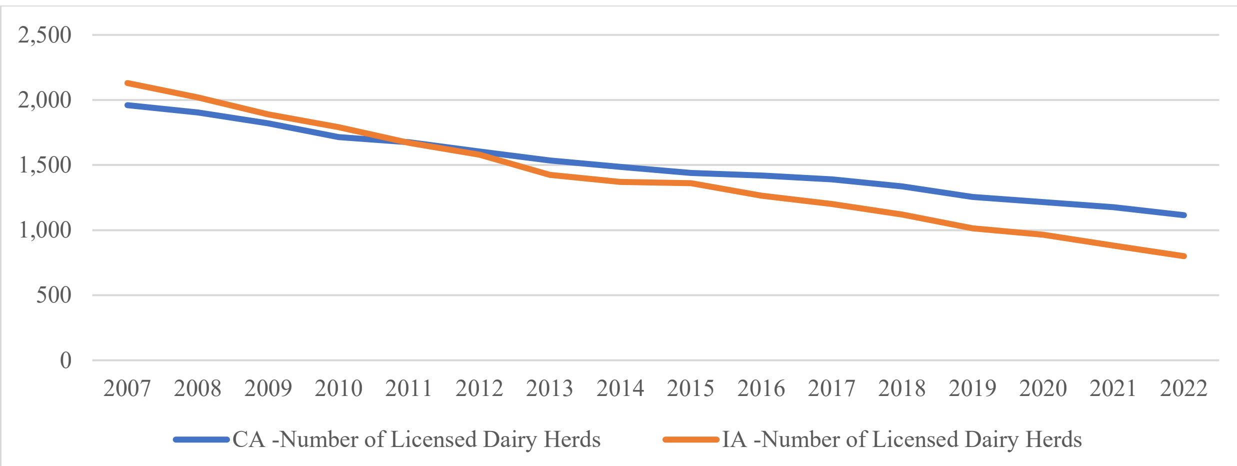
And while the dairies in Table 1 are not currently associated with approved pathways, biogas companies have already indicated their intent to avail themselves of the LCFS to generate credits at several of these facilities. Specifically, Gevo has announced that BP Canada Energy Marketing Corp. and BP Products North America Inc. will market Iowa-produced natural gas in California on its behalf[7]. Gevo is contracting with three of the dairies in Table 1, Meadowvale, Rock River Jerseys and Winding Meadows, two of which have expanded[8]. Another of the dairies

[5] https://www.legis.iowa.gov/docs/publications/LGE/88/SF534.pdf
[6] https://www.legis.iowa.gov/docs/publications/SOL/1224327.pdf#HF522
[7] https://investors.gevo.com/news-releases/news-release-details/gevos-northwest-iowa-rng-project-hits-major-milestone-begins
[8] Gevo appears as the common "cluster" for the dairies here: https://www.epa.gov/sites/default/files/2020-10/agstar-livestock-ad-database.xlsx.

expanding, Kirkman, is partnering with California's Brightmark RNG Origination LLC[9], which sells RNG to U.S. Gain, which is active in the California LCFS market[10].

Based on my study of the effect outside of California of policies to incentivize the use of biodigesters and my review of the literature, I believe similar expansion phenomena are likely taking place in California's dairy sector and elsewhere. The proposed LCFS amendments will increase expansion and concentration[11]. For example, very recently, a local expert has argued that the flattening of the dairy herd in California in the last five years could be linked to biodigesters. Notably, both in California and Iowa, flat and increasing total herd sizes respectively have both been associated with a reduction in the number of diaries, as shown in Figure 1. Consolidation should be a concern for CARB, since there is extensive evidence that it is associated with more water quality problems, among other things[12].

Figure 2 – Number of licensed dairy herds in California and Iowa, 2007-2022




Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

The evidence strongly suggests that the rebound effect is already at work outside California's borders because of race to the bottom policies being enacted by other states. The current policy approach allows for negative crediting of biogas as a way to avoid leakage: the concern is that making California farmers pay for their methane emissions would cause milk production to move (leak) out of state, where emissions are unregulated. But while the approach ensures California farmers do not face an added burden, it does nothing to limit the expansion of dairies in and out of state. As a result, the proposed LCFS amendments likely will cause another type of leakage through the rebound effect: the expansion and concentration of dairy operations resulting

[9] https://www.iowafarmbureau.com/Article/Carbon-neutral
[10] https://biomassmagazine.com/articles/us-gain-to-purchase-rng-from-brightmark-energy-16647
[11] Smith, A. (2022). The Dairy Cow Manure Goldrush. Retrieved from https://asmith.ucdavis.edu/news/revisiting-value-dairy-cow-manure; Smith, A. (2024). Cow Poop is Now a Big Part of California Fuel Policy. Retrieved from https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy .
[12] See for example Bian, Z., H. Tian, Q. Yang, R. Xu, S. Pan, and B. Zhang. 2021. "Production and application of manure nitrogen and phosphorus in the United States since 1860." Earth Syst. Sci. Data 13 (2):515-527. doi: 10.5194/essd-13-515-2021.

from the economic incentives provided by the LCFS and the decreased regulation of dairy operations will likely cause increased methane emissions that are not currently accounted for.

CARB's proposal to increase the carbon intensity target and therefore increase the economic value of methane captured from dairy operations will likely result in the expansion of dairy operations inside and outside of California.

I also want to note that the rebound effect has other substantial negative environmental impacts. In particular, as Table 1 shows, the expansion is occurring largely in Northwest Iowa, where CAFO production is already extremely elevated and there is little if any extra land available for spreading additional manure or digestate. This expansion will likely have both water quality and water quantity effects, and no entity is monitoring or assessing them. Notably, one of the Gevo dairies already leaked an estimated 376,000 gallons of manure water and was fined $10,000 in 2022. Another of the Gevo dairies started construction before receiving permission to do so[13].

This is particularly a concern because in 2017 EPA signed a settlement agreement limiting access to whatever information EPA has at its disposal regarding CAFOs[14] As a result, there is no national database that can be used to establish a national bottom-up[15] baseline of GHG emissions and other forms of pollution from CAFOs. This makes national level tracing of net changes in pollution and emissions as a result of the deployment of biodigesters extraordinarily difficult. In Iowa specifically, the DNR lack of monitoring capacity resulted in a de-delegation petition with EPA in 2007. As a result of the subsequent work plan[16], in 2017 the Iowa Department of Natural Resources identified 5,000 more animal feeding operations, some of which were CAFOs[17]. It is quite evident the Iowa DNR does not have the monitoring capacity to ensure compliance with the assumptions that CARB is making. CARB does not have that capacity either.

Recent changes to the USDA's Natural Resources Conservation Service (NRCS) list of practices eligible to receive subsidies under the Environmental Quality Incentive Program (EQIP) and substantial funding allocated to EQIP in the Inflation Reduction Act (IRA) also make it more likely that the rebound effect will increase in the United States. In particular, NRCS has added eligibility to receive subsidies to additional practices in their Climate-Smart Agriculture and Forestry (CSAF) Mitigation Activities List for FY2024 through EQIP and the Conservation Stewardship Program (CSP)[18]. These activities now include roofs and covers used to cover a waste management facility to capture biogas and waste storage facilities. The increased funding for the EQIP and CSP programs is substantial: $8.45 billion and $3.25 billion respectively[19]. Therefore, there are now subsidies available that will further incentivize the deployment of biodigesters. It is also important to note that CAFO operations that receive both federal subsidies to deploy biodigesters and LCFS subsidies for their methane could legitimately be considered a

[13] https://iowacapitaldispatch.com/2022/07/22/company-with-major-manure-leak-didnt-get-permits-to-build-two-facilities-dnr-says/

[14] Miller, D. L., & Muren, G. (2019). *CAFOs: What We Don't Know Is Hurting Us*, retrieved from https://www.nrdc.org/resources/cafos-what-we-dont-know-hurting-us

[15] Bottom up baselines include individual facilities and can trace aggregate changes to each of them.

[16] https://www.iowadnr.gov/Portals/idnr/uploads/afo/epa_dnr_workplan.pdf

[17] https://publications.iowa.gov/33733/

[18] https://www.nrcs.usda.gov/conservation-basics/natural-resource-concerns/climate/climate-smart-mitigation-activities

[19] https://www.farmers.gov/loans/inflation-reduction-investments

form of double dipping, that is paying twice for the same activity. This raises questions about the additionality of the GHG emissions that could occur.

In my professional opinion, California's ill-conceived policy is poised to trigger a new iteration of Cochrane's treadmill that will result in overproduction, further consolidation, and multiple negative environmental consequences[20]. As in the past, landowners will be the main beneficiaries of the policy. Biodigesters' adopters will benefit from temporary increased profits, overproduction will ensue, and the government will be called in to address the fallout. The climate benefits of this approach are dubious at best.

In summary:

a) CARB has not adequately included a full accounting of greenhouse gas emissions that properly considers the impact of biogas market prices and state-level regulatory settings on the US dairy industry. CARB is also ignoring the expansionary effects of the Inflation Reduction Act and the lack of additionality for methane reductions from digesters funded by the IRA. The information I have shown here regarding already occurring out of state effects illustrates that there does not exist at the moment a comprehensive inventory of biodigesters and it is therefore impossible for CARB to adequately consider national level impacts and back up any claims that the incentives included in the proposed LCFS amendments will not result in industry expansion and consolidation. I have in fact presented evidence that expansion is already occurring in Iowa, it is very strongly associated with the deployment of biodigesters, and an increased market signal to produce more credits will further exacerbate that expansionary effect;

b) The economic incentive to monetize manure-methane emissions as proposed by CARB will likely lead to further expansion in the dairy sector in Iowa. If such expansion were to extend to hog CAFOs, given that Iowa already produces one third of US hogs, the environmental impacts could be devastating considering Iowa alone. The national level effects would be worse;

c) The amendments do not just have the potential to result in direct and indirect environmental impacts in California and other states. Combined with federal policy and enhanced by race to the bottom state deregulation, they will substantially alter incentives and result in industry expansion.

[20]Levins, Richard A., and Willard W. Cochrane. 1996. "The Treadmill Revisited." *Land Economics* 72 (4):550-553. doi: 10.2307/3146915.

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## EDUCATION

1996 - 2000 Iowa State University Ames, IA, USA
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2016-2017 Southern Illinois University Carbondale, IL
*Director, Environmental Resources & Policy Ph.D. Program*
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## BOOK CHAPTERS

11. Lauber K., V. Morris, J. Jacquet, P. Li, I. Moller, S. Secchi, A. Wijeratna, M. De Bona. Forthcoming. The Animal Agriculture Industry's Role in Obstructing Climate Action. In the First Global Assessment of Climate Obstruction (T. Roberts, C. Milani, J. Jacquet, and C. Downie eds.).

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7. Feng H. H., C. Kling L.A. Kurkalova, & S. Secchi. 2007. Subsidies! The Other Incentive-Based Instrument: the Case of the Conservation Reserve Program. In: Moving to Markets in Environmental Regulation: Lessons from Twenty Years of Experience ( J. Freeman & C. Kolstad, eds.) Oxford University Press, New York. [peer reviewed]

6. Gassman P.W., S. Secchi, M. Jha & L.A. Kurkalova. 2006. Upper Mississippi River Basin modeling system part 1: SWAT Input data requirement and Issues. In: Coastal Hydrology and Processes (V.P. Singh & Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

5. Jha M., P.W. Gassman, S. Secchi, & J. Arnold. 2006. Upper Mississippi River Basin modeling system part 2: Baseline Simulation Results In: Coastal Hydrology and Processes (V.P. Singh & Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

4. Kling C.L., S. Secchi, M. Jha, H. Feng, P.W. Gassman, & L.A. Kurkalova. 2006. Upper Mississippi River Basin modeling system part 3: Conservation practice scenario results. In: Coastal Hydrology and Processes (V.P. Singh and Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

3. Secchi S., T. M. Hurley, B. Babcock & R. L. Hellmich. 2006. Managing European Corn Borer Resistance to Bt Corn with Dynamic Refuges. In: Regulating Agricultural Biotechnology: Economics and Policy (R. Just, J. Alston, & D. Zilberman eds.) Springer.

2. Secchi S., & B. A. Babcock. 2003. Pest Mobility, Market Share, and the Efficacy of Using Refuge Requirements for Resistance Management. In: Battling Resistance to Antibiotics and Pesticides: An Economic Approach (R. Laxminarayan, ed.), Resources for the Future, Washington DC. [peer reviewed]

1. Hurley T. M., S. Secchi, B. Babcock, & R. L. Hellmich. 2002. Managing the Risk of European Corn Borer Resistance to Bt Corn, In The Economics Of Managing Biotechnologies (T. Swanson, ed.) Kluwer: Dordrecht, The Netherlands. [peer reviewed article reprint]

## GUEST EDITORSHIPS

Guest Co-Editor for *Economics Research International*'s special issue on the economics of biofuels, http://www.hindawi.com/journals/ecri/si/306959/ .

Guest Co-Editor for *Biomass and Bioenergy*'s special issue on land use change – Vol. 35(6).

## PAPERS UNDER REVIEW

Secchi S. 2023. Wither WOTUS? Understanding the Cost Benefit Analysis of the Waters of the US rule. Revise and resubmit at *Applied Economics Teaching Resources.*

## GRANTS

31. USDA NIFA. #DiverseCornBelt: Resilient Intensification through Diversity in Midwestern Agriculture. (L. Prokopy project PI, Secchi UIowa PI). 2021-2026. $10,000,000 (UIowa $ 467,776).

30. Healthier Workforce Center of the Midwest (NIOSH funding). Agricultural production practices and stress: a pilot study of women farmers in Iowa. (with C. Nichols). 2020-2021, $29,979.

29. NSF EAGER Germination - What we talk about when we talk about big ideas: Using case studies to train PhD students in ideation and questioning processes. Consultant (with A. Charles, N. Becker). 2018-2020, $117,729.

28. UIowa CGRER. A river runs through it: Surveying Iowa City residents' on water use, water quality and flood management (with K.E. Dalrymple). 2018-2020, $30,000.

27. Iowa State University - Land Use Impacts of RFS-Induced Agricultural Expansion 2018-2019, 71,540.

26. Walton Family Foundation - A Scorecard to measure States' Nutrient Reduction Strategies 2017-2019, $19,585.

25. INTERNAL - SIUC Undergraduate Research Assistantship. Creating an Atlas of Southern Illinois' Ecosystem Services. 2015-2016, $2,700.

24. USDA NIFA – Costs of continuous conservation tillage: estimation with incomplete data (with L.A. Kurkalova, T. Wade and R. Claassen), 2016-2018, $499,995.

23. Argonne National Lab (DoE funds) – Landscape by Design – Valuation of Ecosystem Services, 2015-2017, $49,736.

22. National Science Foundation - DYN COUPLED NATURAL-HUMAN. People, Water, and Climate: Adaptation and Resilience in Agricultural Watersheds (with D. Bennett, N. Basu, M. Muste, W. Gutowski) 2011-2017, $1,011,832.

21. Illinois DNR – Training, Certification, Pilot Incentive, Marketing, And Removal Research Project for the long-term strategy in reducing and controlling Asian Carp populations (with J. Garvey), 2011, $1,500,000.

20. National Science Foundation - DYN COUPLED NATURAL-HUMAN. Climate Change, Hydrology, and Landscapes of America's Heartland: A Multi-scale Natural-Human System (With C. Lant, S. Kraft, G. Misma, J. Nicklow, and J. Schoof) 2010-2014, $1,430,000.

19. USDA ERS Cooperative Agreement 58-6000-0-0056. Estimating the costs of continuous conservation tillage. 2010-2014. $30,887.

18. USDA CSREES AFRI Agribusiness Markets and Trade. An Analysis of the Impact of Biofuel Expansion through Linking of Agricultural and Energy Markets (With A. Elobeid and L.A. Kurkalova) 2010-2014, $360,396.

17. The Nature Conservancy. Floodplain Restoration Strategies Integrating Biomass plantings and Ecosystem Service Payments (With S. Kraft) 2009-2013, $112,536.

16. INTERNAL - SIUC Seed Grant. Economic And Environmental Assessment of the Use of Woody Biomass for Energy Production in Southern Illinois, 2009-2010, $14,985 + 1 month of Summer support.

15. INTERNAL - SIUC Undergraduate Research Assistantship. The Role of Federal and State Policy in Promoting Renewable Energy Production. 2009-2010, $5,400.

14. National Science Foundation Cyber-Enabled Discovery and Innovation Type II. Understanding Water-Human Dynamics with Intelligent Digital Watersheds. (with J. Schnoor, M. Muste, A. Kusiak and D. Bennett). 2009-2012, $899,391.

13. EPA, Region 7. Biofuel Feedstock Landscape Coverage for Five Biofuel Industry Scenarios (with R. Cruse, A. Elobeid and S. Tokgoz) 2008-2010, $150,000.

12. Iowa State University Agricultural Systems Initiative. Assessing alternative crop choices and environmental impacts of the bioeconomy: an integrated landscape approach (with M. Duffy and P.W. Gassman) 2007-2008, $15,000.

11. Agricultural Marketing Resource Center. Helping Farmers Make Decisions in the Bioeconomy: Mapping the Potential for Switchgrass in Iowa Relative to Corn and Soybeans. 2007-2008. (with B. Babcock and P.W. Gassman), $75,000.
10. Department of Energy-USDA. Expansion of ethanol production: evaluation of costs and benefits to rural communities in the Upper Mississippi River Basin. (with L. Kurkalova, C.L. Kling, P.W. Gassman, M. Jha, A. Carriquiry and D. Otto) 2006-2009, $676,722.
9. USDA Natural Resources Conservation Service. Environmental Credit Trading Handbook. 2006-2007 (with C.L. Kling), $84,150.
8. Prairie Rivers of Iowa R.C. & D and USDA Natural Resources Conservation Service. Rapid Watershed Assessment for the Boone River, the Upper Iowa and the South Skunk Watersheds (with T. Isenhart, C.L. Kling, P.W. Gassman and M. Tomer) 2006-2007, $72,500.
7. NASA and USDA Cooperative State Research, Education, and Extension Service. Interactive Drivers of Land Use/Land Cover Change in Agricultural Areas: Climate and Land Manager Choices. (with C.L. Kling, H. Feng, P.W. Gassman, and E. Tackle) 2006-2008, $465,900.
6. Iowa Farm Bureau, Leopold Center for Sustainable Development, Iowa Soybean Association, Iowa Corn Growers Association. Assessment of Conservation Practices on Agricultural Cropland in Iowa (with C.L. Kling, H. Feng, P. Gassman, and M. Jha) 2006, $72,500.
5. USDA CSREES Integrated Projects. Water Resource Degradation in the Boone Watershed: Integrating Stakeholder Knowledge and Preferences with Economic and Watershed Models (with C.L. Kling, M. Duffy, L. Kurkalova, H. Feng, P.W. Gassman, and J. Cooper) 2005-2008, $590,000.
4. Prairie Rivers of Iowa R.C. & D and Leopold Center for Sustainable Development. Boone River Watershed and Gordon's Marsh Project (with C.L. Kling, and P.W. Gassman) 2005-2006, $35,000.
3. Iowa State Water Resources Research Institute. Improving Water Quality in Iowa Rivers: Cost-Benefit Analysis of Adopting New Conservation Practices and Changing Agricultural Land Use (with C.L. Kling, H. Feng, P.W. Gassman, and L. Kurkalova) 2005-2006, $39,600.
2. National Science Foundation. Biocomplexity of Integrated Perennial-Annual Agroecosystems (Senior Personnel. Principal Investigators: H. Asbjornsen, R. M Cruse, C.L. Kling, M. Z Liebman, J. D Opsomer) 2005-2007, $ 99,998.
1. Iowa Department of Natural Resources. Costs of Adopting Conservation Practices on Agricultural Cropland in Iowa and Possible Nutrient Standards (with C.L. Kling, H. Feng, P. Gassman, and L. Kurkalova) 2004, $53,360.

## TEACHING EXPERIENCE

Introduction to Sustainability (GEOG 2013). Class for the University's Gen Ed sustainability requirement Average class size 65.

Environmental Economics and Policy (GEOG 3800/5800). Double listed class for undergraduate and graduate students. Average class size: 30.

Environmental Impact Analysis (GEOG 4750). Average class size: 11.

Contemporary Environmental Issues (GEOG 1070). Class for the University's Gen Ed sustainability requirement. Average class size: 370.

Environmental and Energy Economics (GENV 422). Double listed class for undergraduate and graduate students. Average class size: 20.

Geography, People and the Environment (GENV 300i). Class for the University's core curriculum social sciences and interdisciplinary requirement. Average class size: 70.

Environmental Decision Making (Environmental Resources & Policy 502). Core class for the interdisciplinary ER&P Ph.D program. Average class size: 12.

Interdisciplinary Approaches to Environmental Issues (ABE 470). Team taught class, capstone for the Minor in Environmental Studies.

## GRADUATE STUDENT ADVISEMENT

MASTERS STUDENT ADVISER
Amy Kopale – Masters in Geography, UIowa, 2019
Aleesandria Gonzalez- Masters in Geography, SIUC, 2017
Daniel Fucik - Masters in Geography, SIUC, 2016
Andisiwe Stuurman - Masters in Geography, SIUC (Fulbright scholar), 2015
Mohamud Esmail – Masters in Agribusiness Economics, SIUC, 2011
Alison Britt – Masters in Agribusiness Economics, SIUC, 2011
Kent Rupp – Masters in Agribusiness Economics, SIUC, 2011

PH.D. STUDENT ADVISER
Austin Holland – Ph.D. in Geography, UIowa, 2022
Shanna McClain (with C. Bruch) – Ph.D. in Environmental Resources & Policy, SIUC (IGERT fellow), 2016
Mukesh Bhattarai – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Awoke Teshager (with J. Schoof) – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Tom Shaw – Ph.D. in Environmental Resources & Policy, SIUC, 2015
Sarah Varble – Ph.D. in Environmental Resources & Policy, SIUC, 2014

MASTERS STUDENT COMMITTEE MEMBER
Tracy Fidler – Masters in Natural Resources and Environmental Sciences, UIUC, 2017
Jodie Hancock – Masters in Forestry, SIUC, 2017
Ann Rushing – Masters in Geography, SIUC, 2015
Brent Ritzler – Masters in Public Administration, SIUC, 2015
Lance Odum – Masters in Public Administration, SIUC, 2012
Andrew Johnson – Masters in Geography, SIUC, 2012

PH.D. STUDENT COMMITTEE MEMBER
Asif Rahman – Ph.D. in Geography, UIowa, current
Enes Yildirim – Ph.D. in Water Resources, UIowa, current
Oronde Drakes – Ph.D. in Geography, UIowa, current
Rebecca Kauten – Ph.D. in Geography, UIowa, 2019
Clara Mundia – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Amanda Marshall – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Dat Tran- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Ross Guida – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Obed Quaicoe- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Artur Rombenso – Ph.D. in Zoology, SIUC, 2016
Wahid Rahman – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Tim Stoebner – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Steve Randall - Ph.D. in Energy & Environmental Systems, NCA&T University, 2012
Caroline Gottschalk Druschke – Ph.D in Rethoric, University of Illinois at Chicago, 2011

## PROCEEDINGS

Jones, C., & S. Secchi. 2019. Reconciling Climate Change with Nitrate Impairment of Drinking Water: Policies for Iowa's Largest City. SUS-RURI: Developing a Convergence SUS Agenda for Redesigning the Urban-Rural Interface along the Mississippi River Watershed, Iowa State University and NSF, August 12-13, Ames, Iowa.

Kurkalova L. A., S. Secchi & P. W. Gassman. 2009. Greenhouse Gas Mitigation Potential of Corn Ethanol: Accounting for Corn Acreage Expansion. Proceedings of the 2007 National Conference on Environmental Science and Technology. G.Uzochukwu,; Schimmel, K.; Chang, S.-Y.; Kabadi, V.; Luster-Teasley, S.; Reddy, G.; Nzewi, E. (Eds.). Springer. p. 251-257.

Secchi S., P. W. Gassman, M. Jha, L. Kurkalova, & C. L. Kling. 2008. Water Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest. Proceedings of the Farm Foundation Conference: "Transition to a Bioeconomy: Environmental and Rural Development Impacts", October 15-16, 2008, Hyatt Regency At Union Station, St. Louis, MO. URL: [http://www.farmfoundation.org/news/articlefiles/401-Final_version_Farm_Foundation%20feb%2020%2009.pdf](http://www.farmfoundation.org/news/articlefiles/401-Final_version_Farm_Foundation%20feb%2020%2009.pdf)

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels. Proceedings of the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Gassman, P.W., S. Secchi, & M. Jha. 2008. Assessment of bioenergy-related scenarios for the Boone River watershed in north central Iowa. In: Proceedings of the 21st Century Watershed Technology: Improving Water Quality and Environment Conference, March 29-April 3, American Society of Agricultural and Biological Engineers, Concepción, Chile.

Gassman, P.W., S. Secchi, & M. Jha. 2007. An alternative approach for analyzing wetlands in SWAT for the Boone River watershed in north central Iowa. In: *4th International SWAT Conference Book of Abstracts*, July 3-7, UNESCO-IHE, Institute for Water Education, Delft, Netherlands.

Gassman, P.W., S. Secchi, & M. Jha. 2006. Application of SWAT for the Boone River watershed in north central Iowa. Presented at the American Society of Agricultural and Biological Engineers Annual Meeting, July 9-12, Portland, OR. ASABE Paper 062234, St. Joseph, MI.

Secchi S., H. H. Feng, L. A. Kurkalova, C. L. Kling, P. W. Gassman, & M. Jha. 2005. Nonpoint source needs assessment for Iowa part II: the cost of improving Iowa's water quality. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.522-532.

Gassman, P.W., S. Secchi, M. Jha, L.A. Kurkalova, H.Feng, & C.L. Kling. 2005. Nonpoint source needs assessment for Iowa part III: economic and environmental outcomes. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.533-542.

Gassman, P.W., S. Secchi, C.L. Kling, M. Jha, L.A. Kurkalova, & H.Feng. 2005. An analysis of the 2004 Iowa Diffuse Pollution Needs assessment using SWAT. *Proceedings of the SWAT 2005 3rd International Conference*, pp. 291-30111-15 July, Zurich, Switzerland.

Jha, M., P.W. Gassman, S. Secchi, J.G. Arnold, L.A. Kurkalova, H. Feng, & C.L. Kling. 2005. An assessment of alternative conservation practice and land use strategies on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 444-453, July 11-15, Zurich, Switzerland.

Takle, E. S., M. Jha, P. W. Gassman, C. J. Anderson, & S. Secchi. 2005. Climate change impacts on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 599-608. July 11-15, Zurich, Switzerland.

Feng H., C. L. Kling, L. A. Kurkalova, S. Secchi, & P. W. Gassman. 2005. The Conservation Reserve Program in the Presence of a Working Land Alternative: Implications for Environmental Quality, Program Participation, and Income Transfer. *American Journal of Agricultural Economics* 87 (5).

Jha M., P. W. Gassman, S. Secchi, & J. Arnold. 2003. Configuration of SWAT for the Upper Mississippi River Basin: an application to two subwatersheds. Proceedings of the Total Maximum Daily Load (TMDL) Environmental Regulations II, 8-12 November 2003, Albuquerque, New Mexico.

Secchi S. & B. A. Babcock. 2002. Pearls before Swine? Potential Trade-Offs Between the Human and Animal Use of Antibiotics. *American Journal of Agricultural Economics* 84 (5).

## WORKING PAPERS

Dodder R.S., A. Elobeid, T. L. Johnson, P. O. Kaplan, L. A. Kurkalova, S. Secchi, & S. Tokgoz. 2011. Environmental Impacts of Emerging Biomass Feedstock Markets: Energy, Agriculture, and the Farmer. CARD Working Paper [11-WP 526].

Secchi S. 2007. Watching corn grow: a hedonic study of the Iowa landscape. Working paper 07-WP 445, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, H.H. Feng, T. Campbell, & C.L. Kling. 2005. The Cost of Clean Water: Assessing Agricultural Pollution Reduction at the Watershed Scale. Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., M. Jha, L.A. Kurkalova, H.H. Feng, P.W. Gassman, & C.L. Kling. 2005. The Designation of Co-benefits and Its Implication for Policy: Water Quality versus Carbon Sequestration in Agricultural Soils. Working paper 05-WP 389, Center for Agricultural and Rural Development, Ames, Iowa.

Kurkalova L.A., C. Burkart, & S. Secchi. 2004. Cropland Cash Rental Rates in the Upper Mississippi River Basin. Technical report 04-TR 47, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. 2002. Patient Behavior and Antibiotic Prescriptions: the Equilibrium Level of Antibiotic Use and the Role of a Market Permit System. Center for Agricultural and Rural Development, Ames, Iowa.

Babcock B.A., J. Beghin, M. Duffy, H.H. Feng, B. Hueth, C.L. Kling, L.A. Kurkalova, U. Schneider, S. Secchi, Q. Weninger, & J. Zhao. 2001. Conservation Payments: Challenges in Design and Implementation. Working paper 01-BP 34, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. & B.A. Babcock. 2001. Optimal Antibiotic Usage with Resistance and Endogenous Technological Change. Working paper 01-WP 269, Center for Agricultural and Rural Development, Ames, Iowa.

Hurley T.M., S. Secchi, B.A. Babcock, & R. L. Hellmich. 1999. Managing the Risk of European Corn Borer Resistance to Transgenic Corn: An Assessment of Refuge Recommendations. Staff Report 99-Sr 88, Center for Agricultural And Rural Development, Ames, Iowa.

## OTHER PUBLICATIONS

Vasto A., & Secchi S., 2021, Rural Water Systems in Iowa: Analysis of Opportunities and Challenges. Iowa Environmental Council. URL: https://www.iaenvironment.org/newsroom/water-and-land-news/council-releases-rural-water-system-report

Secchi S., & D. Cwiertny. 2019. Iowa's Grants to Counties Program: A Valuable but Underutilized Program for Protecting the Public Health of Private Well Users. University of Iowa Center for Health Effects of Environmental Contamination Policy Report 2019-01. URL: https://cheec.uiowa.edu/sites/cheec.uiowa.edu/files/CHEEC-2019-01_Grants_To_Counties_3_.pdf

Healy M.*, & S. Secchi. 2016. A Comparative Analysis of Ecosystem Service Valuation Decision Support Tools for Wetland Restoration. A Report Prepared for the Association of State Wetland Managers. URL: http://www.aswm.org/pdf_lib/ecosystem_service_valuation_032116.pdf

Secchi S. 2015. Background paper on Economic Valuation of Ecosystem Services from Working Lands Conservation, prepared for USDA's ERA and NRCS Economic Valuation of Conservation Based Ecosystem Services Workshop.

Braden J. & S. Secchi, 2014, C-FARE and AAEA Webinar "Policy Innovations in Nonpoint Source Pollution-policy". Friday, March 21, 2014.

Cooke S. L., A. C. Lloyd*, A. D. Monteblanco, & Silvia Secchi, 2013. Ecosystems, Economics, and Equity in the Floodplain. A case study developed for the National Socio-Environmental Synthesis Center Project Teaching Socio-Environmental Synthesis with Case Studies. URL: http://www.sesync.org/ecosystems-economics-and-equity-in-the-floodplain-case-study-5

Secchi S., 2009. Overview Presentation. NRCS and C-FARE Webinar "Environmental Markets: New Approaches for Natural Resources Management Webinar", February 23rd, 2009

Feng H., L. A. Kurkalova & S. Secchi. 2001. Multifunctionality: Market failure and options to internalise externalities: Applying the OECD framework - A review of literature in the USA, Consultant background paper for the OECD workshop "Multifunctionality: Applying the OECD Analytical Framework, Guiding Policy Design", July 2001.

## INVITED CONFERENCE AND SEMINAR PRESENTATIONS

Invited plenary presentation, "Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture", Sustainable Phosphorus Summit, November 1-2, 2022, Raleigh NC.

Invited presentation, Economic & Land Use Policies to Limit Nutrient Pollution: Perspectives from the Great Lakes and Beyond, Alliance for the Great Lakes, April 4, 2022, virtual event.

Seminar presentation, "A lonely stick amongst many carrots: The Conservation Compliance Program in the 21st Century", Paul H. O'Neill School, Indiana University, February 25, 2021, virtual event.

Seminar presentation, "The US census of agriculture as lens and mirror of long term changes in the rural Midwest", Faculty of Land and Food Systems, University of British Columbia, September 16 2020, virtual event.

Invited presentation "The role of policy in promoting sustainable floodplain management" at Emiquon Science 2015: River Floodplain Restoration and Connection, February 19th, 2015, Lewistown, IL

Invited Presentation "Understanding the links between humans, climate change, water and carbon in a Corn Belt Watershed", at the AGU Fall meeting, December 15-19th, 2014, San Francisco, CA.

Invited presentation "Promoting Bioenergy Crops: An economic perspective on challenges and opportunities" at the workshop Incorporating Bioenergy in Sustainable Landscape Designs Workshop Two: Agricultural Landscapes June 24–26th, 2014, Argonne National Laboratory, IL.

Invited presentation "Increased Biofuel Production and Water Resources" at the National Academies Roundtable on Science and Technology for Sustainability, May 20-21, 2014, Washington DC. URL: http://sites.nationalacademies.org/cs/groups/pgasite/documents/webpage/pga_088191.pdf

Invited speaker at the Indiana University-Purdue University first "Rivers of the Anthropocene" conference, January 23-24th, 2014, Indianapolis, IN.

Invited speaker at the MISI-ZIIBI: Living with the Great Rivers, Climate Adaptation Strategies in the Midwest River Basins, co-sponsored by Washington University in St. Louis and the Royal Netherlands Embassy, March 23rd, 2013, St. Louis, MO.

Plenary speaker at the 2013 Missouri River Natural Resources Conference and BiOp Forum "Beyond the Banks" March 12th, 2013, Jefferson City, MO.

Luncheon speaker at the Soil and Water Conservation Society Modeling Summit 2011 - Advancing the Science of Modeling, March 30th, 2011, Denver, CO.

Invited lecture to the "Food, Energy, and Quality of Life in Iowa" graduate class at Iowa State University, on the difference between ecological and environmental economics approaches to agricultural policy, September 21st, 2009.

North Carolina A&T State University, Energy and Environmental Systems Seminar, April 12th, 2010.

Iowa State University Biobased Industry Center Energy Camp, May 21st 2010.

University of Minnesota, Applied Economics Department, Environmental and Resource Economics Seminar, April 26th 2010.

University of Illinois at Urbana-Champaign, Department of Agricultural and Consumer Economics Seminar, September 10th 2010.

University of Iowa, Department of Geography, Kohn Colloquium, October 29th 2010.

## CONFERENCE PAPERS AND POSTERS

Secchi S. 2022. Water Quality and Adaptation to Climate Change. Iowa Organic Conference, November 20-21, Iowa City, IA.

Secchi S. 2022. Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture. Phosphorus Week, November 1-4, Raleigh, NC.

Secchi S. 2020. Understanding the Cost Benefit Analysis of the Waters of the US rule. Presidential Session on Pedagogical Tools: Fundamental Concepts and Methods. Annual Meeting of the Southern Economic Association, November 21-23 (virtual).

Secchi S. 2020. Regulatory Environmental Cost-Benefit Analysis: A Case Study of the Waters of the United States Rule. Innovations in Teaching Environmental and Resource Economics ENV/TLC Track session of the Annual Meeting of the Agricultural & Applied Economics Association, August 5 (virtual).

Secchi S. 2019. The State of Water Quality Strategies in the Mississippi River Basin: Is Cooperative Federalism Working? American Water Resources Association, Annual Water Resources Conference, November 3-6, Salt Lake City, UT.

Secchi S. 2015. The push and pull of conservation, energy and climate mitigation policies on agricultural landscapes: the case of conservation tillage. Conference on Complex Systems, September 26-30, Tempe, AZ.

Secchi S. 2015. The potential of conservation tillage payments as a climate mitigation strategy. AAG Annual Meeting, April 21-25, Chicago, IL.

Eichholz M. W., R. T. Alisauskas, J. O. Leafloor, S. Varble, & S. Secchi. 2013. Feasibility of Commercial Wildlife Exploitation as a Management Tool: Snow Geese as a Case Study of Overabundance. 20th Annual Conference of The Wildlife Society, October 5-10, Milwaukee, WI.

Secchi S. & S. Varble. 2013. We Can Beat Them If We Eat Them: Assessing the Marketing Potential of the Asian Carp in the US. Symposium on the Culture, Biology, and Management of Asian Carps in North America, 143rd Annual Meeting of the American Fisheries Society, September 8-12, Little Rock, AR.

Wade T., L.A. Kurkalova, & S. Secchi. 2013. Estimation of Discrete Choice Models with Aggregate Data: An Application to the Adoption of Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Secchi S. & L.A. Kurkalova. 2013. Estimating the Cost of Supplying Greenhouse Gas Offsets with Continuous Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Varble S., & S. Secchi. The Role of Watershed Management Groups and Key Stakeholders in the Resilience and Sustainability on a Rural Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Varble S., D. Varble & S. Secchi. Potential for Perennial Crops for Bioenergy Production: Results of a Survey from an Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Smith S., S. Varble & S. Secchi. 2013. Fish Consumers: Purchasing Habits and Environmental concerns. Selected Poster for the 2013 Annual ICHRIE Summer Conference, July 24-27, St. Louis, MO.

Wade T., L.A. Kurkalova, & S. Secchi. 2012. Using the Logit Model with Aggregated Choice Data in Estimation of Iowa Corn Farmers' Conservation Tillage Subsidies. AAEA Annual Meeting, August 12-14, Seattle, WA.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. 31st USAEE/IAEE North American Conference, November 4-7, Austin, TX.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. AERE Session at the Southern Economics Association Annual Meeting Nov 16-18, New Orleans, LA.

Secchi S. 2012. Integrating Biofuel Production and Mitigation Strategies Into Agricultural Landscapes. Bioenergy and Biodiversity: Oxymoron or Opportunity? Symposium at the Ecological Society of America Annual Meeting, 5-10 August, Portland, OR.

Kurkalova L.A., R. Dodder, A. Elobeid, T. Johnson, O. Kaplan, S. Secchi, & S. Tokgoz. 2011. Land-Use Impacts of Emerging Biomass Feedstock Markets: Accounting for Agricultural and Energy Market Interactions and the Variability of Local Conditions. Association of Environmental and Resource Economists' Inaugural Summer Conference, 9 - 10 June, Seattle, WA.

Secchi S., S. Esling, C. Lant, & J. A. Koropchak. 2011. The Environmental Resources and Policy Ph.D. Program at Southern Illinois University Carbondale: a Success Story. Facilitating Interdisciplinary Research and Education Symposium, March 28-29, Boulder, CO.

Secchi S., J. Fargione, J. Remo, B. Moseley, T. Strole & S. Kraft. 2010. Stacking Ecosystem Services in Reconnected Floodplains: Linking Socioeconomic and Biophysical Analysis to Improve Floodplain Management. Selected paper at the Soil and Water Conservation Society Annual Meeting, July 18-21, St. Louis, MO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2010. Potential Water Quality Changes Due to Corn Expansion in The Upper Mississippi River Basin. Selected paper at the 4th World Congress of Environmental and Resource Economists, June 28-July 2, 2010, Montréal, Canada.

Kurkalova, L.A., S. Randall, & S. Secchi. 2010. Land-Use Implications of the Changes in Energy Prices. Selected Poster at the Agricultural and Applied Economics Association 2010 Annual Meeting, July 25-27, 2010, Denver, CO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2009. The Water Quality Effects of Corn Expansion in the Midwest. Selected poster at the USDA, USGS, EPA and SWCS "Science to Solutions (Gulf Hypoxia)" workshop on December 9-11, 2009 Des Moines, IA.

Secchi S. 2009. Balancing Conservation Policy: Targeting Ecosystem Service Provision with Feedstock Production for the Bioeconomy in the Midwestern U.S. Invited presentation at the organized Symposium: "Integrating science and policy for watershed sustainability: Balancing hydrological services, quality of life, and economic vitality" (OOS #4185) at the Ecological Society of American Annual Meeting August 2-7 2009, Albuquerque, NM.

Secchi S., L.A. Kurkalova P.W. Gassman, & B. Babcock. 2009. Land Use and Environmental Impacts of Corn Grain vs. Cellulosic Ethanol: Policy Implication. Selected paper at the 2009 SWCS Annual Conference July 11-15, Dearborn, MI.

Secchi S. (Invited speaker). 2009. Ethanol Production and the Mississippi River, an Economic Perspective. 2009 Mississippi River Conference: "Visions of a Sustainable Mississippi River: Merging Ecological, Economic, and Cultural Values", organized by the National Great Rivers Research and Education Center and The Nature Conservancy, August 10 – 13, 2009, Collinsville, IL.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Harvesting Corn Stover and Crop Residue Management: The Impact of Conflicting Economic Incentives, Selected Poster at the Annual AERE Workshop - 2009 Theme: Energy and the Environment, Washington, DC June 18-20, 2009.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected paper at the SWCS Annual Conference July 11-15, 2009, Dearborn, MI.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected Poster at the AAEA & ACCI Joint Annual Meeting in Milwaukee, WI, July 26–28, 2009.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Rotation and Water Quality Effects of Harvesting Corn Stover, Selected AERE paper at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session 3059).

Secchi S., P.W. Gassman, & B.A. Babcock. 2008. Land Use and Environmental Impacts of Corn Grain versus Cellulosic Ethanol: a GIS Approach, Selected paper at the 28th USAEE/IAEE North American Conference, "Unveiling the Future of Energy Frontiers.", December 3-5 2008, New Orleans, LA, USA.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest, Selected paper at the Farm Foundation Conference: Transition to a Bioeconomy: Environmental and Rural Development Impacts, October 15-16 2008, St. Louis, MO.

Secchi S., L.A. Kurkalova, J.C. Tyndall, P.W. Gassman, & C.L. Kling. 2008. The Next Step for the Bioeconomy: Mapping the Impact of Corn Stover Use on Crop Choice, Land Use, and Environmental Quality". Selected poster at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session M56).

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels, Overview presentation at the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Secchi S., L.A. Kurkalova, C.L. Kling, J. Cooper, P.W. Gassman, & M. Jha. 2006. Water Resource Degradation in the Boone Watershed: Integrating Economic and Watershed Models. Soil and Water Conservation Society workshop "Managing Agricultural Landscapes for Environmental Quality: Strengthening the Science Base", Kansas City, MO, October 2006.

Secchi S. 2005. Watching Corn Grow: a Hedonic Study of the Iowa Landscape, Eastern Economic Association Annual Conference, New York City, NY, March 2005.

Secchi S. 2001. Models to Support TMDL Development Across the Midwest (Symposium), American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., & B.A. Babcock. 2001. Optimal Pesticide Usage with Resistance and Endogenous Technological Change, American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., T. M. Hurley, & R. L. Hellmich. 2001. Managing European Corn Borer Resistance to Bt Corn with Dynamic Refuges, 5th ICABR International Conference, Ravello, Italy, June 2001.

Secchi S., & B.A. Babcock. 1999. A Model of Pesticide Resistance as a Common Property and Exhaustible Resource, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

Secchi S., & B.A. Babcock. 1999. Managing Pest Resistance: The Potential Of Crop Rotations And Shredding, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

## PROFESSIONAL ACTIVITIES

Editorial Board of Conservation, Review Editor, Frontiers, 2019-present

Editorial Board, Applied Economic Perspectives and Policy, 2015-present

Oklahoma EPSCoR External Advisory Board Member 2017-2018

Participant at invitation-only Purdue University University of Illinois workshop "Scientific Challenges to Operationalizing Payments for Agro-Ecosystem Services (PAgES)" (organized by Ben Gramig and Sylvie Brouder). Indianapolis, IN, November 2017

Consultant, Walton Family Foundation – Developing a Score Card for Iowa and Illinois' Nutrient Reduction Strategies. 2016-2017

Program Committee Member for the 6th World Congress of Environmental and Resource Economists, 2018

National Science Foundation, panelist, 2010, 2011, 2014, 2016, 2017, 2018, 2019 and 2023. Ad hoc reviewer, 2012, 2013, 2014, 2016, 2017

USDA – NIFA panelist, 2017 and 2018. Ad hoc reviewer 2014 and 2016

Reviewer for Selected Paper Sessions of the American Agricultural Economics Association meetings, 2002, 2003, 2008 and 2016

Author of working paper II for the USDA and C-FARE workshop, 'Economic Valuation of Conservation Based Ecosystem Services', July 21, 2015, Washington, DC

Participant, inaugural SESYNC short course, Teaching Socio-Environmental Synthesis with Case Studies, July 23-26, 2013, Annapolis, MD

Planning Committee Member, AWRA 2013 Spring Specialty Conference: "Agricultural Hydrology and Water Quality II", March 25-27, St. Louis, MO

Participant, NSF workshop on Developing and Sustaining Interdisciplinary Graduate Programs, 7-8 October 2012, Coeur d'Alene, ID

EPA Star Fellowship Panelist, 2012

Program Committee Member for the 18th and 19th Annual Meetings of the European Association of Environmental and Resource Economists, 2011 and 2012

Member of the Middle Mississippi Wetland Field Station Advisory Committee Southern Illinois University, 2009- 2017

Rapporteur at the JRC/EEA/OECD Expert Consultation: "Review and inter-comparison of modeling land use change effects of bioenergy", Paris, France, 29-30 January 2009

Reviewer for the National Institutes for Water Resource - U.S. Geological Survey Competitive Grants Program, 2009 and 2011

Reviewer for the Collaborative, Highly Interdisciplinary Research Program at the Swiss Federal Institute of Technology, Zurich Research Commission, 2009

Reviewer for Selected Paper Sessions of the 3rd World Congress of Environmental and Resource Economists, 2006

Reviewer for USDA-CSREES Conservation Effects Assessment Project, 2005 and 2006

Reviewer of the Union of Concerned Scientists' report "CAFOs Uncovered: The Untold Costs of Confined Animal Feeding Operations" URL: http://www.ucsusa.org/food_and_environment/sustainable_food/cafos-uncovered.html.

Reviewer for: Agriculture, Agricultural and Resource Economics Review, Agriculture and Human Values, Agronomy Journal, Appetite, American Journal of Agricultural Economics, Applied Economic Perspectives and Policy, Applied Geography, Biofuels, Biological Invasions, Biomass & Bioenergy, BioScience, Choices, Ecology, Ecological Applications, Ecological Economics, Ecosystem Services, Energy Policy, Environmental and Development Economics, Environmental and Resource Economics, Environmental Management, Environmental Research

Letters, Environmental Science & Technology, Frontiers of Ecology and the Environment, GCB Bioenergy, Intelligent Systems in Accounting, Finance and Management, International Journal of Digital Earth, Journal of Agricultural and Applied Economics, Journal of Agricultural and Resource Economics, Journal of Applied Geography, Journal of Environmental Economics and Management, Journal of Great Lakes Research, Journal of Soil and Water Conservation, Land Use Policy, Landscape and Urban Planning, Journal of Natural Resources Policy Research, Journal of Soil and Water Conservation, Nature Climate Change, PLoS ONE, SAGE Open (Article Editor), Science of the Total Environment, Society & Natural Resources, Sustainability, Proceedings of the National Academies of Science, Transactions of ASABE

## UNIVERSITY SERVICE

2019 – current, Governmental Relations Committee

2019 – current, Office of Sustainability Advisory Board

2019 – current, Center for Global & Regional Environmental Research Executive Committee

2018 – current, Center for Health Effects of Environmental Contamination Executive Committee

2020 – 2021, Sustainability Investment & Purchasing Practices Subcommittee

2019 – 2022, Underrepresented Students in Sustainability Mentoring Program Mentor

2018 – 2022, Faculty Assembly

## ACADEMIC HONORS AND AWARDS

Southern Illinois University Early Career Faculty Excellence Award, 2012 [inaugural winner].

Yellow Ribbon Poster Presentation, with L.A. Kurkalova, and P. W. Gassman, Agricultural and Applied Economics Association, 2009.

2009 Editor's Choice Award, Journal of Soil and Water Conservation: Secchi, S., J. Tyndall, L.A. Schulte, and H. Asbjornsen. 2008. High crop prices and conservation: Raising the stakes. *Journal of Soil and Water Conservation* 63(3):68A-73A.

Iowa State University College of Agriculture and Life Science Team Award, to the Resource and Environmental Policy Division. 2008.

Second Place Poster Presentation, with M. Jha, L.A. Kurkalova, C.L. Kling, H. Feng, P.W. Gassman, and T. Campbell, American Agricultural Economics Association, 2005 and 2006.

Second Place Poster Presentation, with C.L. Kling, H. Feng, L.A. Kurkalova, P.W. Gassman, M. Jha, T. Campbell, A. Bhaskar, C. Burkart, S. Sengupta and R. Olson, American Agricultural Economics Association, 2004.

First Place Poster Presentation, with C.L. Kling, L.A. Kurkalova, and P.W. Gassman, American Agricultural Economics Association, 2003.

Outstanding Ph.D. Dissertation (Honorable Mention), American Agricultural Economics Association, 2001.

Professional Advancement Travel Grant, Iowa State University, 1999.

Premium for Academic Excellence Award, Iowa State University, 1996.

## OUTREACH PRESENTATIONS AND PODCASTS

2021-2023 – We All Want Clean Water – Podcast co-host and producer (31 episodes)

2023 - The Power of Big Pork – Foodprint podcast

2022 - Iowa's Industrial Agriculture – The Checkout podcast

2022 - "Cows, Climate and Culture Wars: Putting Bad Policy Out to Pasture" virtual panel, Center for Biological Diversity.

2022 - "Human Rights and Climate Change: Iowa's Challenges & Opportunities" virtual panel, UI Center for Human Rights and the Environmental Law Initiative.

2022 – "Celebrating 50 years of the Clean Water Act", panel, Sierra Club, Waterloo, IA.

2020 – Webinars on Agriculture and Climate Change for the Iowa Farmers Union and Environment Iowa

2019 – Science Café, The current state of the Paris agreement, Fairfield and Mount Vernon, IA

2018 – Wonk Wednesday, America out of Paris: the current state of global climate change policy, University of Iowa, Iowa City, Iowa, United States

2018 – Rapid Response History, Liquid Gold or Fool's Gold? Biofuels in the US, University of Iowa, Iowa City, Iowa, United States

2011 – Carbondale Science Café' – Presentation on Biofuels, March 24

2009 – Speaker, "No Silver Bullets: Unintended Consequences Of Oil And Water Solutions", May 18, Indo-American Center, Chicago, IL

2008-2013 – The View: Expert opinions on a special series on energy for The Southern Illinoisan newspaper. 22 short perspectives 2022

## SELECTED MEDIA

- Farmers Could Be the Nation's Leading Environmentalists *Mother Jones* 2024
- The myths we tell ourselves about American farming *Vox* 2023
- The Biden Administration Bets Big on 'Climate Smart' Agriculture *FERN/Yale360* 2023
- Opinion/Solutions: Ancient grain may help with climate change *The Atlanta Journal Constitution*
- Don't be fooled by exaggerated 'benefits' of carbon pipelines *Des Moines Register Opinion* 2022
- As Congress funds high-tech climate solutions, it also bets on a low-tech one: Nature *The Washington Post* 2022
- Expansion of a Lucrative Dairy Digester Market is Sowing Environmental Worries in the U.S. *Inside Climate News.* 2022
- Climate change is making it harder to provide clean drinking water in farm country *NPR*
- How Corn Ethanol for Biofuel Fed Climate Change *Civil Eats* 2022
- North Carolina's Department of Environmental Quality is facing its second complaint for permitting hog waste operations in poor communities of color *The Counter* 2021
- The USDA Wants to Make Farms Climate-Friendly. Will It Work? *Mother Jones/FERN* 2021
- Regenerative agriculture needs a reckoning *The Counter* 2021
- Tom Vilsack for USDA? Expect more inaction on hunger, discrimination, pollution and rural decline *Des Moines Register Opinion* 2021
- The Approaching Climate Crisis: What EPA Rollbacks Mean For Water And Air Quality In The Midwest, *Iowa Public Radio River to River* 2020

- Iowa scientists urge state leaders to use pandemic, derecho to prep for climate change, *Iowa City Press-Citizen* 2020
- Iowa's water quality strategy is not working. Here's what should be done instead. *Des Moines Register Opinion* (with Neil Hamilton, Matt Liebman, and Chris Jones) 2020
- Iowa Farmers Face Climate-Fueled Destruction, While the Industry Says it's 'Just Weather', *Civil Eats* 2020
- Democrats court Iowa farmers on climate, conservation, *E&E News* 2020
- Report: Many Iowa counties underusing private well testing funds, *The Gazette* 2019

## MEMBERSHIPS

Agricultural & Applied Economics Association

Association of American Geographers

Association of Environmental and Resource Economists

Ecological Society of America

# ATTACHMENT B

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

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February 14, 2024

Ellison Folk
Shute Mihaly & Weinberger LLP
396 Hayes Street
San Francisco, CA 94102

**Subject: Comments on the Proposed Amendments to the Low Carbon Fuel Standard**

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Dear Ms. Folk,

SWAPE was retained by Shute Mihaly & Weinberger LLP to provide written comments on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") released by the California Air Resources Board ("CARB"), specifically the *Staff Report: Initial Statement of Reasons* ("ISOR") and the *Appendix D: Draft Environmental Impact Analysis for the Proposed Low Carbon Fuel Standard Regulation* ("EIA").[1, 2] Upon review, I have found that the ISOR and EIA inadequately addressed the following:

- Anaerobic digestate increases the potential for nitrate contamination of groundwater; and
- Anaerobic digestate increases $N_2O$ and NOx emissions into the atmosphere; and
- Anaerobic digestate increases ammonia emissions, which is an odorous compound. Odor associated with anaerobic digestate soil application can result in odor complaints to nearby communities which are often of lower socioeconomic status resulting in environmental justice issues.

In "Table 1.1: Summary of Potential Environmental Impacts" in the ISOR, CARB listed the following impacts as "Potentially Significant and Unavoidable":[3]

- "Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality"

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[1] ISOR.pdf.
[2] EIA.pdf.
[3] ISOR. PDF Pg. 64-65.

- "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils"
- "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality"

Upon review, I find the ISOR and EIA are insufficient in addressing my concerns regarding anaerobic digesters' air quality and groundwater impacts. The following are my comments regarding these documents.

# Anaerobic Digestion

## Anaerobic Digester Digestate Impact on Air

In the ISOR, CARB listed the impacts of "Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality" as "Potentially Significant and Unavoidable".[4] The following section highlights a clear indication that CARB's analysis fell short in adequately assessing the significance of these impacts on air quality.

Anaerobic digestion efficiently decomposes waste into smaller molecules, enhancing their propensity to volatilize into the atmosphere. During the anaerobic digestion process, quantities of ammonia are produced as a byproduct. This odorous compound possesses the potential to cause irritation and discomfort to the throat, lungs, and eyes, and prolonged exposure to elevated ammonia levels can lead to lung damage.[5] Furthermore, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[6] From a study by Rosenfeld et. al. in 2000, anaerobic digestion can emit enough ammonia to contribute to odor emissions. The study mentions:

> *"Odor emissions from land application of biosolids have become a concern for biosolids managers. Chemical odorant emissions from biosolids were identified using gas chromatography-mass spectrometry and included dimethyl disulfide (DMDS), dimethyl sulfide (DMS), carbon disulfide (CS2), ammonia (NH3), trimethyl amine (TMA), and acetone."*[7]

This confirms that ammonia emissions from biosolids (digestate) are broken down during the anaerobic digestion process, potentially leading to increased ammonia concentration and, consequently, odor and health irritation.

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[4] ISOR. PDF Pg. 64-65.

[5] Centers for Disease Control and Prevention. *Ammonia: Exposure, Decontamination, Treatment*. Last Reviewed: February 6, 2023.

[6] New York State Department of Health. The Facts About Ammonia. Updated: July 28, 2004.

[7] Rosenfeld, P.E., and Henry C. L., (2000). Wood ash control of odor emissions from biosolids application. Journal of Environmental Quality. Vol 29, 1662-1668.

Another study, conducted by Holly et al. in 2017, evaluated the effects of anaerobic digestion on greenhouse gas and ammonia emissions during manure storage. According to Holly et al., anaerobic digestion can increase ammonia emissions. The study stated that the anaerobic digestion process "resulted in a gas emission tradeoff as it increased $NH_3$ [ammonia] emissions by 81% during storage, which could be mitigated by subsequent SLS [solid-liquid separation], manure storage covers, or other beneficial management practices."[8] The study further explains:

> *"During the AD process, methanogens and other microorganisms break down proteins, amino acids, and urea forming NH4 (Bernet et al., 2000). In addition, mineralization of organic N and volatile fatty acids during AD increases manure pH and available N (Petersen and Sommer, 2011), factors which increase NH3 emissions."*[9]

Holly et al. also found that nitrous oxide emissions were increased from anaerobically digested solids during storage:

> *"Overall, the methane emissions from storage were reduced by manure processing by 25%, 46%, and 68% for AD, SLS, and AD+SLS, respectively. However, these reductions from storage were somewhat negated when examing [sic] total GHG's to 44% and 27% for SLS and AD+SLS due to N2O losses from solid storage."*[10]

They concluded that greenhouse gas emissions were not further reduced when solid-liquid separation was employed in addition to anaerobic digestion as opposed to anaerobic digestion alone, as "anaerobically stacking digested solids increased emissions of N2O negating abatement of total GHG."[11] The findings of this study show the importance of considering nitrous oxide emissions from digestate solids in cumulative GHG emissions, which CARB failed to adequately address in the EIA. Furthermore, the ISOR and EIA claim methane reductions are achieved by digesters without any discussion of digestate-related $N_2O$, which Holly (2017) found negated methane reductions by more than 40 percent.

As anaerobic digestion breaks down organic material, biogas is produced. Preble et. al. (2020) explained that during biogas combustion in the anaerobic digestion process, ammonia is oxidized to nitrous oxides, which, in turn, increases nitrous oxide emissions.[12] The study "quantifies emission rates of GHGs, criteria air pollutants, and toxic/odorous compounds from the AD composting process."[13] The study further states:

> *"In situ measurements of key sources at two large-scale industrial facilities in California were conducted to quantify pollutant emission rates across the AD composting*

[8] Holly et al., (2017). Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application.
[9] Ibid.
[10] Id. PDF Pg. 7.
[11] Id. PDF Pg. 9.
[12] Preble et. al. (2020). *Air Pollutant Emission Rates for Dry Anaerobic Digestion and Composting of Organic Municipal Solid Waste*. PDF Pg 2.
[13] Ibid.

*process. These measurements established a strong relationship between flared biogas ammonia (NH3) content and emitted nitrogen oxides (NOx), indicating that fuel NOx formation is significant and dominates over the thermal or prompt NOx pathways when biogas NH3 concentration exceeds ∼200 ppm."*[14]

The above study highlights a crucial aspect, noting that "biogas may contain significant amounts of ammonia ($NH_3$) that is produced during the degradation of amino acids during acidogenesis - one of the four primary stages in AD."[15] Additionally, it emphasizes the potential consequences, explaining that "the oxidation of $NH_3$ present in the biogas to nitrogen oxides ($NOx = NO + NO_2$) can cause elevated flare emissions that contribute to air quality problems and exceed permitted levels."[16]

Anaerobic digesters produce significant amounts of greenhouse gases, such as methane and carbon dioxide.[17] Notably, the combustion of biogas in an internal combustion engine yields high levels of air pollution, including carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide ($SO_2$), and various hazardous air pollutants.[18] Biogas combustion also results in formaldehyde emissions. According to the EPA, formaldehyde is a "probable" carcinogen.[19] Based on an article by the Vermont Department of Environmental Conservation, anaerobic digesters can result in increased formaldehyde emissions from combustion of biogas. The article states:

*"The use of internal combustion engines to burn biogas also generates substantially more formaldehyde emissions than would occur with other fuels or other combustion devices. According to the U.S. Environmental Protection Agency (US EPA), formaldehyde is ubiquitous and naturally occurring in the environment at low levels, contributing to asthma and eye and respiratory irritation. At higher concentration, it can cause severe irritation and is considered a probable human carcinogen by the US EPA."*[20]

The impact of emissions from anaerobic digestion on nearby communities, especially those in close proximity to dairy farms, is a critical aspect of environmental justice and public health. The emissions from anaerobic digestion can disproportionately affect nearby communities, particularly those adjacent to dairy farms, often comprising lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

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[14] Id. PDF Pg 1.
[15] Ibid.
[16] Id. PDF pg 2.
[17] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.
[18] Ibid.
[19] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Formaldehyde. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[20] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.

The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on air quality.

## Anaerobic Digester Digestate Impact on Groundwater

In the ISOR, CARB listed the impacts of "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils" and "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality" as "Potentially Significant and Unavoidable".[21] This section serves as a response to CARB's analysis of these impacts.

Anaerobic digestion breaks down waste into a digestate of smaller molecules that are more susceptible to leaching into the groundwater. Several studies have found that anaerobic digestion leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate. The leaching of nitrates into drinking water and food can lead to the onset of blue baby syndrome, also known as methemoglobinemia.[22] The consumption of nitrate reduces the ability of red blood cells to transport oxygen, leading to illness in infants younger than 12 months and presenting as a distinctive blue or brown tint to their skin.[23]

*Figure 1. Baby with methemoglobinemia* [24]

[21] ISOR. PDF Pg. 64-65.
[22] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.
[23] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.
[24] St. Bartholomew's Hospital, London/Photo Researchers (n.d.). American Scientist.

Lamolinara et al. (2022) found that digestate, the nutrient-rich product from anaerobic digestion of organic waste, can "contribute to nutrient pollution without comprehensive management strategies."[25] This type of pollution can lead to harmful algal blooms, hypoxia, and eutrophication.[26] Improper application of digestate has the potential to adversely affect both plant growth and soil health.[27] The chemical composition of digestate can present challenges for sustainable disposal.[28] Early application of digestate may lead to nutrient loss, translocation to deeper soil layers, or discharges of $NO3^-$ into groundwater.[29]

Anaerobic digestion breaks down waste, rendering it more susceptible to seepage into groundwater than undigested manure. Treatment lagoons are used to facilitate the waste treatment process and are lined, inhibiting nitrate from entering the groundwater. Anaerobic digestate is more extensively broken down compared to sludge from treatment lagoons. One study by Agga et al. (2022) indicated that treatment lagoons can reduce nitrogen compared to aerobic digestion:

> *"Unlike anaerobic digesters, uncovered lagoons are open to the air, photosynthesizing bacteria may develop that act to reduce nitrogen and sulfur-containing compounds and help eliminate odor in the effluent storage layer."*[30]

Nitrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater. A 2010 study titled "Biogas Digestates as Organic Fertilizer in Different Crop Rotations" assessed bioenergy cropping systems for yield performance, ecological impacts, and economic feasibility. The research revealed that treatments with high digestate application rates could elevate the risk of $NO3^-$ discharges into groundwater.[31] Another study, by Fermoso et al. in 2019, highlighted that the prolonged use of digestate from anaerobic digesters could result in rapid nitrification of ammonium (NH4+-N) in the soil, making it readily accessible to crops and prone to leaching, potentially causing groundwater pollution.[32] A study by Amon et al. (2006) found that anaerobic digester digestate increases nitrate loss potential.[33] The study states:

> *"Anaerobic digestion reduces manure carbon and dry matter content by about 50%. NH4-N content and pH in digested slurry are higher than in untreated slurry (Messner, 1988). Thus, potentials for NH3 emissions during slurry storage are enhanced. Due to*

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[25] Lamolinara et al. (2022). Anaerobic digestate management, environmental impacts, and techno-economic challenges. PDF Pg. 1.
[26] Ibid.
[27] Id. PDF Pg. 2.
[28] Ibid.
[29] Ibid.
[30] Agga et al. (2022). Lagoon, Anaerobic Digestion, and Composting of Animal Manure Treatments Impact on Tetracycline Resistance Genes. PDF Pg. 7.
[31] Formowitz and Fritz (2010). Biogas Digestates as Organic Fertilizer in Different Crop Rotations. PDF Pg. 4.
[32] Fermoso et al. (2019). Trace Elements in Anaerobic Biotechnologies. IWA. June 2019. PDF Pg. 187.
[33] Amon et al. (2006). Methane, nitrous oxide and ammonia emissions during storage and after application of dairy cattle slurry and influence of slurry treatment.

*the reduced dry matter content, biogas slurry can infiltrate more rapidly into the soil, which reduces NH3 emissions after slurry application. However, the increased NH4-N content and pH give rise to higher NH3 loss potentials."*[34]

There is a potential for nitrate contamination of groundwater, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[35] The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on groundwater quality.

## Conclusion: Anaerobic Digester Impacts Inadequately Evaluated

CARB failed to adequately address air quality, soil and geology, and groundwater quality issues in the ISOR and EIA. Further analysis is required to quantify the impact of increased anaerobic digesters and the impacts on groundwater and air quality, especially in locations where digestate is applied to soil. Further assessment is essential to properly evaluate the impact of emissions to air and discharges to groundwater from anaerobic digestion on nearby communities, specifically lower-income neighborhoods.

# Disclaimer

SWAPE has received limited discovery regarding this project. Additional information may become available in the future; thus, we retain the right to revise or amend this report when additional information becomes available. Our professional services have been performed using that degree of care and skill ordinarily exercised, under similar circumstances, by reputable environmental consultants practicing in this or similar localities at the time of service. No other warranty, expressed or implied, is made as to the scope of work, work methodologies and protocols, site conditions, analytical testing results, and findings presented. This report reflects efforts which were limited to information that was reasonably accessible at the time of the work, and may contain informational gaps, inconsistencies, or otherwise be incomplete due to the unavailability or uncertainty of information obtained or provided by third parties.

Sincerely,

Paul Rosenfeld

Paul E. Rosenfeld, Ph.D.

Attachment A: Paul E. Rosenfeld CV

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[34] Ibid.

[35] Mahony et al. (2002) Feasibility Study for Centralised Anaerobic Digestion for Treatment of Various Waste and Wastewaters in Sensitive Catchment Areas. PDF Pg. 5.

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

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# *Paul Rosenfeld, Ph.D.*

**Chemical Fate and Transport & Air Dispersion Modeling**

*Principal Environmental Chemist*

**Risk Assessment & Remediation Specialist**

## Education

Ph.D. Soil Chemistry, University of Washington, 1999. Dissertation on volatile organic compound filtration.

M.S. Environmental Science, U.C. Berkeley, 1995. Thesis on organic waste economics.

B.A. Environmental Studies, U.C. Santa Barbara, 1991. Focus on wastewater treatment.

## Professional Experience

Dr. Rosenfeld has over 25 years of experience conducting environmental investigations and risk assessments for evaluating impacts to human health, property, and ecological receptors. His expertise focuses on the fate and transport of environmental contaminants, human health risk, exposure assessment, and ecological restoration. Dr. Rosenfeld has evaluated and modeled emissions from oil spills, landfills, boilers and incinerators, process stacks, storage tanks, confined animal feeding operations, industrial, military and agricultural sources, unconventional oil drilling operations, and locomotive and construction engines. His project experience ranges from monitoring and modeling of pollution sources to evaluating impacts of pollution on workers at industrial facilities and residents in surrounding communities. Dr. Rosenfeld has also successfully modeled exposure to contaminants distributed by water systems and via vapor intrusion.

Dr. Rosenfeld has investigated and designed remediation programs and risk assessments for contaminated sites containing lead, heavy metals, mold, bacteria, particulate matter, petroleum hydrocarbons, chlorinated solvents, pesticides, radioactive waste, dioxins and furans, semi- and volatile organic compounds, PCBs, PAHs, creosote, perchlorate, asbestos, per- and poly-fluoroalkyl substances (PFOA/PFOS), unusual polymers, fuel oxygenates (MTBE), among other pollutants. Dr. Rosenfeld also has experience evaluating greenhouse gas emissions from various projects and is an expert on the assessment of odors from industrial and agricultural sites, as well as the evaluation of odor nuisance impacts and technologies for abatement of odorous emissions. As a principal scientist at SWAPE, Dr. Rosenfeld directs air dispersion modeling and exposure assessments. He has served as an expert witness and testified about pollution sources causing nuisance and/or personal injury at sites and has testified as an expert witness on numerous cases involving exposure to soil, water and air contaminants from industrial, railroad, agricultural, and military sources.

## Professional History:

Soil Water Air Protection Enterprise (SWAPE); 2003 to present; Principal and Founding Partner
UCLA School of Public Health; 2007 to 2011; Lecturer (Assistant Researcher)
UCLA School of Public Health; 2003 to 2006; Adjunct Professor
UCLA Environmental Science and Engineering Program; 2002-2004; Doctoral Intern Coordinator
UCLA Institute of the Environment, 2001-2002; Research Associate
Komex $H_2O$ Science, 2001 to 2003; Senior Remediation Scientist
National Groundwater Association, 2002-2004; Lecturer
San Diego State University, 1999-2001; Adjunct Professor
Anteon Corp., San Diego, 2000-2001; Remediation Project Manager
Ogden (now Amec), San Diego, 2000-2000; Remediation Project Manager
Bechtel, San Diego, California, 1999 – 2000; Risk Assessor
King County, Seattle, 1996 – 1999; Scientist
James River Corp., Washington, 1995-96; Scientist
Big Creek Lumber, Davenport, California, 1995; Scientist
Plumas Corp., California and USFS, Tahoe 1993-1995; Scientist
Peace Corps and World Wildlife Fund, St. Kitts, West Indies, 1991-1993; Scientist

## Publications:

**Rosenfeld P.E.** and Spaeth K.R., (2023) Authors' Response to Letter to the Editor from Bullock and Ramacciotti, Volume 234, https://doi.org/10.1007/s11270-023-06165-3

**Rosenfeld P.E.,** Spaeth K.R., Remy L.L., Byers V., Muerth S.A., Hallman R,C., Summers-Evans J., Barker S. (2023) Perfluoroalkyl substances exposure in firefighters: Sources and implications, Environmental Research, Volume 220, https://doi.org/10.1016/j.envres.2022.115164.

**Rosenfeld P. E.,** Spaeth K., Hallman R., Bressler R., Smith, G., (2022) Cancer Risk and Diesel Exhaust Exposure Among Railroad Workers. *Water Air Soil Pollution.* **233,** 171.

Remy, L.L., Clay T., Byers, V., **Rosenfeld P. E.** (2019) Hospital, Health, and Community Burden After Oil Refinery Fires, Richmond, California 2007 and 2012. *Environmental Health.* 18:48

Simons, R.A., Seo, Y. **Rosenfeld, P**., (2015) Modeling the Effect of Refinery Emission On Residential Property Value. Journal of Real Estate Research. 27(3):321-342

Chen, J. A, Zapata A. R., Sutherland A. J., Molmen, D.R., Chow, B. S., Wu, L. E., **Rosenfeld, P. E.,** Hesse, R. C., (2012) Sulfur Dioxide and Volatile Organic Compound Exposure To A Community In Texas City Texas Evaluated Using Aermod and Empirical Data. *American Journal of Environmental Science*, 8(6), 622-632.

**Rosenfeld, P.E**. & Feng, L. (2011). *The Risks of Hazardous Waste.* Amsterdam: Elsevier Publishing.

Cheremisinoff, N.P., & **Rosenfeld, P.E.** (2011). *Handbook of Pollution Prevention and Cleaner Production: Best Practices in the Agrochemical Industry*, Amsterdam: Elsevier Publishing.

Gonzalez, J., Feng, L., Sutherland, A., Waller, C., Sok, H., Hesse, R., **Rosenfeld, P.** (2010). PCBs and Dioxins/Furans in Attic Dust Collected Near Former PCB Production and Secondary Copper Facilities in Sauget, IL. *Procedia Environmental Sciences*. 113–125.

Feng, L., Wu, C., Tam, L., Sutherland, A.J., Clark, J.J., **Rosenfeld, P.E.** (2010). Dioxin and Furan Blood Lipid and Attic Dust Concentrations in Populations Living Near Four Wood Treatment Facilities in the United States. *Journal of Environmental Health*. 73(6), 34-46.

Cheremisinoff, N.P., & **Rosenfeld, P.E.** (2010). *Handbook of Pollution Prevention and Cleaner Production: Best Practices in the Wood and Paper Industries.* Amsterdam: Elsevier Publishing.

Cheremisinoff, N.P., & **Rosenfeld, P.E.,** (2009). *Handbook of Pollution Prevention and Cleaner Production: Best Practices in the Petroleum Industry*. Amsterdam: Elsevier Publishing.

Wu, C., Tam, L., Clark, J., **Rosenfeld, P**. (2009). Dioxin and furan blood lipid concentrations in populations living near four wood treatment facilities in the United States. *WIT Transactions on Ecology and the Environment, Air Pollution,* 123 (17), 319-327.

Cheremisinoff, N.P., **Rosenfeld, P.E.** Davletshin, A.R. (2008). ***Responsible Care***. Gulf Publishing. Texas.

Tam L. K.., Wu C. D., Clark J. J. and **Rosenfeld, P.E.** (2008). A Statistical Analysis Of Attic Dust And Blood Lipid Concentrations Of Tetrachloro-p-Dibenzodioxin (TCDD) Toxicity Equivalency Quotients (TEQ) In Two Populations Near Wood Treatment Facilities. *Organohalogen Compounds*, 70, 002252-002255.

Tam L. K.., Wu C. D., Clark J. J. and **Rosenfeld, P.E.** (2008). Methods For Collect Samples For Assessing Dioxins And Other Environmental Contaminants In Attic Dust: A Review. *Organohalogen Compounds*, 70, 000527-000530.

Hensley, A.R. A. Scott, J. J. J. Clark, **Rosenfeld, P.E.** (2007). Attic Dust and Human Blood Samples Collected near a Former Wood Treatment Facility. *Environmental Research*. 105, 194-197.

**Rosenfeld, P.E.,** J. J. J. Clark, A. R. Hensley, M. Suffet. (2007). The Use of an Odor Wheel Classification for Evaluation of Human Health Risk Criteria for Compost Facilities. *Water Science & Technology* 55(5), 345-357.

**Rosenfeld, P. E.,** M. Suffet. (2007). The Anatomy Of Odour Wheels For Odours Of Drinking Water, Wastewater, Compost And The Urban Environment. *Water Science & Technology* 55(5), 335-344.

Sullivan, P. J. Clark, J.J.J., Agardy, F. J., **Rosenfeld, P.E.** (2007). *Toxic Legacy, Synthetic Toxins in the Food, Water, and Air in American Cities.* Boston Massachusetts: Elsevier Publishing

**Rosenfeld, P.E.,** and Suffet I.H. (2004). Control of Compost Odor Using High Carbon Wood Ash. *Water Science and Technology*. 49(9),171-178.

**Rosenfeld P. E.,** J.J. Clark, I.H. (Mel) Suffet (2004). The Value of An Odor-Quality-Wheel Classification Scheme For The Urban Environment. *Water Environment Federation's Technical Exhibition and Conference (WEFTEC) 2004*. New Orleans, October 2-6, 2004.

**Rosenfeld, P.E.,** and Suffet, I.H. (2004). Understanding Odorants Associated With Compost, Biomass Facilities, and the Land Application of Biosolids. *Water Science and Technology*. 49(9), 193-199.

**Rosenfeld, P.E.,** and Suffet I.H. (2004). Control of Compost Odor Using High Carbon Wood Ash, *Water Science and Technology*, 49( 9), 171-178.

**Rosenfeld, P. E**., Grey, M. A., Sellew, P. (2004). Measurement of Biosolids Odor and Odorant Emissions from Windrows, Static Pile and Biofilter. *Water Environment Research*. 76(4), 310-315.

**Rosenfeld, P.E.,** Grey, M and Suffet, M. (2002). Compost Demonstration Project, Sacramento California Using High-Carbon Wood Ash to Control Odor at a Green Materials Composting Facility. *Integrated Waste Management Board Public Affairs Office*, Publications Clearinghouse (MS–6), Sacramento, CA Publication #442-02-008.

**Rosenfeld, P.E**., and C.L. Henry. (2001). Characterization of odor emissions from three different biosolids. *Water Soil and Air Pollution*. 127(1-4), 173-191.

**Rosenfeld, P.E.,** and Henry C. L., (2000). Wood ash control of odor emissions from biosolids application. *Journal of Environmental Quality*. 29, 1662-1668.

**Rosenfeld, P.E.,** C.L. Henry and D. Bennett. (2001). Wastewater dewatering polymer affect on biosolids odor emissions and microbial activity. *Water Environment Research*. 73(4), 363-367.

**Rosenfeld, P.E.,** and C.L. Henry. (2001). Activated Carbon and Wood Ash Sorption of Wastewater, Compost, and Biosolids Odorants. *Water Environment Research*, 73, 388-393.

**Rosenfeld, P.E.,** and Henry C. L., (2001). High carbon wood ash effect on biosolids microbial activity and odor. *Water Environment Research*. 131(1-4), 247-262.

Chollack, T. and **P. Rosenfeld. (**1998). Compost Amendment Handbook For Landscaping. Prepared for and distributed by the City of Redmond, Washington State.

**Rosenfeld, P. E.** (1992). The Mount Liamuiga Crater Trail. *Heritage Magazine of St. Kitts*, 3(2).

**Rosenfeld, P. E.** (1993). High School Biogas Project to Prevent Deforestation On St. Kitts. *Biomass Users Network*, 7(1).

**Rosenfeld, P. E. (**1998). Characterization, Quantification, and Control of Odor Emissions From Biosolids Application To Forest Soil. Doctoral Thesis. University of Washington College of Forest Resources.

**Rosenfeld, P. E.** (1994). Potential Utilization of Small Diameter Trees on Sierra County Public Land. Masters thesis reprinted by the Sierra County Economic Council. Sierra County, California.

**Rosenfeld, P. E. (**1991). How to Build a Small Rural Anaerobic Digester & Uses Of Biogas In The First And Third World. Bachelors Thesis. University of California.

## Presentations:

**Rosenfeld, P.E**., "The science for Perfluorinated Chemicals (PFAS): What makes remediation so hard?" Law Seminars International, (May 9-10, 2018) 800 Fifth Avenue, Suite 101 Seattle, WA.

**Rosenfeld, P.E.,** Sutherland, A; Hesse, R.; Zapata, A. (October 3-6, 2013). Air dispersion modeling of volatile organic emissions from multiple natural gas wells in Decatur, TX. *44th Western Regional Meeting, American Chemical Society.* Lecture conducted from Santa Clara, CA.

Sok, H.L.; Waller, C.C.; Feng, L.; Gonzalez, J.; Sutherland, A.J.; Wisdom-Stack, T.; Sahai, R.K.; Hesse, R.C.; **Rosenfeld, P.E.** (June 20-23, 2010). Atrazine: A Persistent Pesticide in Urban Drinking Water. *Urban Environmental Pollution*. Lecture conducted from Boston, MA.

Feng, L.; Gonzalez, J.; Sok, H.L.; Sutherland, A.J.; Waller, C.C.; Wisdom-Stack, T.; Sahai, R.K.; La, M.; Hesse, R.C.; **Rosenfeld, P.E.** (June 20-23, 2010). Bringing Environmental Justice to East St. Louis, Illinois. *Urban Environmental Pollution.* Lecture conducted from Boston, MA.

**Rosenfeld, P.E**. (April 19-23, 2009). Perfluoroctanoic Acid (PFOA) and Perfluoroactane Sulfonate (PFOS) Contamination in Drinking Water From the Use of Aqueous Film Forming Foams (AFFF) at Airports in the United States. *2009 Ground Water Summit and 2009 Ground Water Protection Council Spring Meeting*, Lecture conducted from Tuscon, AZ.

**Rosenfeld, P.E.** (April 19-23, 2009). Cost to Filter Atrazine Contamination from Drinking Water in the United States" Contamination in Drinking Water From the Use of Aqueous Film Forming Foams (AFFF) at Airports in the United States. *2009 Ground Water Summit and 2009 Ground Water Protection Council Spring Meeting*. Lecture conducted from Tuscon, AZ.

Wu, C., Tam, L., Clark, J., **Rosenfeld, P**. (20-22 July (2009). Dioxin and furan blood lipid concentrations in populations living near four wood treatment facilities in the United States. Brebbia, C.A. and Popov, V., eds., *Air Pollution XVII: Proceedings of the Seventeenth International Conference on Modeling, Monitoring and Management of Air Pollution*. Lecture conducted from Tallinn, Estonia.

**Rosenfeld, P. E.** (October 15-18, 2007). Moss Point Community Exposure To Contaminants From A Releasing Facility. *The 23rd Annual International Conferences on Soils Sediment and Water.* Platform lecture conducted at University of Massachusetts, Amherst MA.

**Rosenfeld, P. E.** (October 15-18, 2007). The Repeated Trespass of Tritium-Contaminated Water Into A Surrounding Community Form Repeated Waste Spills From A Nuclear Power Plant. *The 23rd Annual International Conferences on Soils Sediment and Water*. Platform lecture conducted from University of Massachusetts, Amherst MA.

**Rosenfeld, P. E.** (October 15-18, 2007). Somerville Community Exposure To Contaminants From Wood Treatment Facility Emissions. The *23rd Annual International Conferences on Soils Sediment and Water*. Lecture conducted from University of Massachusetts, Amherst MA.

**Rosenfeld P. E.** (March 2007). Production, Chemical Properties, Toxicology, & Treatment Case Studies of 1,2,3-Trichloropropane (TCP). *The Association for Environmental Health and Sciences (AEHS) Annual Meeting*. Lecture conducted from San Diego, CA.

**Rosenfeld P. E.** (March 2007). Blood and Attic Sampling for Dioxin/Furan, PAH, and Metal Exposure in Florala, Alabama. *The AEHS Annual Meeting.* Lecture conducted from San Diego, CA.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (August 21 – 25, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *The 26th International Symposium on Halogenated Persistent Organic Pollutants – DIOXIN2006*. Lecture conducted from Radisson SAS Scandinavia Hotel in Oslo Norway.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (November 4-8, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *APHA 134 Annual Meeting & Exposition.* Lecture conducted from Boston Massachusetts.

**Paul Rosenfeld Ph.D**. (October 24-25, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. Mealey's C8/PFOA. *Science, Risk & Litigation Conference.* Lecture conducted from The Rittenhouse Hotel, Philadelphia, PA.

**Paul Rosenfeld Ph.D**. (September 19, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, *Toxicology and Remediation PEMA Emerging Contaminant Conference*. Lecture conducted from Hilton Hotel, Irvine California.

**Paul Rosenfeld Ph.D**. (September 19, 2005). Fate, Transport, Toxicity, And Persistence of 1,2,3-TCP. *PEMA Emerging Contaminant Conference.* Lecture conducted from Hilton Hotel in Irvine, California.

**Paul Rosenfeld Ph.D**. (September 26-27, 2005). Fate, Transport and Persistence of PDBEs. *Mealey's Groundwater Conference.* Lecture conducted from Ritz Carlton Hotel, Marina Del Ray, California.

**Paul Rosenfeld Ph.D**. (June 7-8, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. *International Society of Environmental Forensics: Focus on Emerging Contaminants*. Lecture conducted from Sheraton Oceanfront Hotel, Virginia Beach, Virginia.

**Paul Rosenfeld Ph.D**. (July 21-22, 2005). Fate Transport, Persistence and Toxicology of PFOA and Related Perfluorochemicals. *2005 National Groundwater Association Ground Water and Environmental Law Conference*. Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

**Paul Rosenfeld Ph.D**. (July 21-22, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, Toxicology and Remediation. *2005 National Groundwater Association Ground Water and Environmental Law Conference.* Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

**Paul Rosenfeld, Ph.D.** and James Clark Ph.D. and Rob Hesse R.G. (May 5-6, 2004). Tert-butyl Alcohol Liability and Toxicology, A National Problem and Unquantified Liability. *National Groundwater Association. Environmental Law Conference*. Lecture conducted from Congress Plaza Hotel, Chicago Illinois.

**Paul Rosenfeld, Ph.D.** (March 2004). Perchlorate Toxicology. *Meeting of the American Groundwater Trust*. Lecture conducted from Phoenix Arizona.

Hagemann, M.F., **Paul Rosenfeld, Ph.D.** and Rob Hesse (2004). Perchlorate Contamination of the Colorado River. *Meeting of tribal representatives*. Lecture conducted from Parker, AZ.

**Paul Rosenfeld, Ph.D.** (April 7, 2004). A National Damage Assessment Model For PCE and Dry Cleaners. *Drycleaner Symposium. California Ground Water Association*. Lecture conducted from Radison Hotel, Sacramento, California.

**Rosenfeld, P. E**., Grey, M., (June 2003) Two stage biofilter for biosolids composting odor control. *Seventh International In Situ And On Site Bioremediation Symposium Battelle Conference* Orlando, FL.

**Paul Rosenfeld, Ph.D.** and James Clark Ph.D. (February 20-21, 2003) Understanding Historical Use, Chemical Properties, Toxicity and Regulatory Guidance of 1,4 Dioxane. *National Groundwater Association. Southwest Focus Conference. Water Supply and Emerging Contaminants*.. Lecture conducted from Hyatt Regency Phoenix Arizona.

**Paul Rosenfeld, Ph.D.** (February 6-7, 2003). Underground Storage Tank Litigation and Remediation. *California CUPA Forum*. Lecture conducted from Marriott Hotel, Anaheim California.

**Paul Rosenfeld, Ph.D**. (October 23, 2002) Underground Storage Tank Litigation and Remediation. *EPA Underground Storage Tank Roundtable*. Lecture conducted from Sacramento California.

**Rosenfeld, P.E**. and Suffet, M. (October 7- 10, 2002). Understanding Odor from Compost, *Wastewater and Industrial Processes. Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

**Rosenfeld, P.E**. and Suffet, M. (October 7- 10, 2002). Using High Carbon Wood Ash to Control Compost Odor. *Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

**Rosenfeld, P.E.** and Grey, M. A. (September 22-24, 2002). Biocycle Composting For Coastal Sage Restoration. *Northwest Biosolids Management Association*. Lecture conducted from Vancouver Washington..

**Rosenfeld, P.E**. and Grey, M. A. (November 11-14, 2002). Using High-Carbon Wood Ash to Control Odor at a Green Materials Composting Facility. *Soil Science Society Annual Conferenc*e. Lecture conducted from Indianapolis, Maryland.

**Rosenfeld. P.E.** (September 16, 2000). Two stage biofilter for biosolids composting odor control. *Water Environment Federation.* Lecture conducted from Anaheim California.

**Rosenfeld. P.E. (**October 16, 2000). Wood ash and biofilter control of compost odor. *Biofest.* Lecture conducted from Ocean Shores, California.

**Rosenfeld, P.E. (**2000). Bioremediation Using Organic Soil Amendments. *California Resource Recovery Association*. Lecture conducted from Sacramento California.

**Rosenfeld, P.E**., C.L. Henry, R. Harrison. (1998). Oat and Grass Seed Germination and Nitrogen and Sulfur Emissions Following Biosolids Incorporation with High-Carbon Wood-Ash. *Water Environment Federation 12th Annual Residuals and Biosolids Management Conference Proceedings*. Lecture conducted from Bellevue Washington.

**Rosenfeld, P.E.**, and C.L. Henry. (1999). An evaluation of ash incorporation with biosolids for odor reduction. *Soil Science Society of America*. Lecture conducted from Salt Lake City Utah.

**Rosenfeld, P.E.**, C.L. Henry, R. Harrison. (1998). Comparison of Microbial Activity and Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Brown and Caldwell.* Lecture conducted from Seattle Washington.

**Rosenfeld, P.E.**, C.L. Henry. (1998). Characterization, Quantification, and Control of Odor Emissions from Biosolids Application To Forest Soil. *Biofest.* Lecture conducted from Lake Chelan, Washington.

**Rosenfeld, P.E,** C.L. Henry, R. Harrison. (1998). Oat and Grass Seed Germination and Nitrogen and Sulfur Emissions Following Biosolids Incorporation with High-Carbon Wood-Ash. Water Environment Federation 12th Annual Residuals and Biosolids Management Conference Proceedings. Lecture conducted from Bellevue Washington.

**Rosenfeld, P.E.**, C.L. Henry, R. B. Harrison, and R. Dills. (1997). Comparison of Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Soil Science Society of America*. Lecture conducted from Anaheim California.

## Teaching Experience:

UCLA Department of Environmental Health (Summer 2003 through 20010) Taught Environmental Health Science 100 to students, including undergrad, medical doctors, public health professionals and nurses. Course focused on the health effects of environmental contaminants.

National Ground Water Association, Successful Remediation Technologies. Custom Course in Sante Fe, New Mexico. May 21, 2002. Focused on fate and transport of fuel contaminants associated with underground storage tanks.

National Ground Water Association; Successful Remediation Technologies Course in Chicago Illinois. April 1, 2002. Focused on fate and transport of contaminants associated with Superfund and RCRA sites.

California Integrated Waste Management Board, April and May, 2001. Alternative Landfill Caps Seminar in San Diego, Ventura, and San Francisco. Focused on both prescriptive and innovative landfill cover design.

UCLA Department of Environmental Engineering, February 5, 2002. Seminar on Successful Remediation Technologies focusing on Groundwater Remediation.

University Of Washington, Soil Science Program, Teaching Assistant for several courses including: Soil Chemistry, Organic Soil Amendments, and Soil Stability.

U.C. Berkeley, Environmental Science Program Teaching Assistant for Environmental Science 10.

## Academic Grants Awarded:

California Integrated Waste Management Board. $41,000 grant awarded to UCLA Institute of the Environment. Goal: To investigate the effect of high carbon wood ash on volatile organic emissions from compost. 2001.

Synagro Technologies, Corona California: $10,000 grant awarded to San Diego State University.
Goal: investigate the effect of biosolids for restoration and remediation of degraded coastal sage soils. 2000.

King County, Department of Research and Technology, Washington State. $100,000 grant awarded to University of Washington: Goal: To investigate odor emissions from biosolids application and the effect of polymers and ash on VOC emissions. 1998.

Northwest Biosolids Management Association, Washington State. $20,000 grant awarded to investigate effect of polymers and ash on VOC emissions from biosolids. 1997.

James River Corporation, Oregon: $10,000 grant was awarded to investigate the success of genetically engineered Poplar trees with resistance to round-up. 1996.

United State Forest Service, Tahoe National Forest: $15,000 grant was awarded to investigating fire ecology of the Tahoe National Forest. 1995.

Kellogg Foundation, Washington D.C. $500 grant was awarded to construct a large anaerobic digester on St. Kitts in West Indies. 1993

## Deposition and/or Trial Testimony:

In the United States District Court for the Western District of Louisiana
Ricky Bush v. Clean Harbors Colfax LLC
Case No. 1:22-cv-02026-DDD-JPM
Rosenfeld Deposition 12-18-2023

In United States District Court of Hawaii
Patrick Feindt, Jr. et al. vs. The United States of America
Case No. 1:22-cv-LEK-KJM
Rosenfeld Deposition 11-29-2023

In the Circuit Court for the Twentieth Judicial Circuit St. Clair County, Illinois
Timothy Gray vs. Rural King et al.
Case No 2022-LA-355
Rosenfeld Deposition 9-26-2023

In United States District Court Eastern District of Wisconsin
Gary L. Siepe vs. Soo Line Railroad Company
Case No. 2:21-cv-00919
Rosenfeld Deposition 9-15-2023

In the Circuit Court of Cook County Illinois
Donald Fox vs. BNSF
Case No. 2021 L12
Rosenfeld Deposition 9-12-2023

In the Court of Common Please Cuyahoga County, Ohio
Thomas Schleich vs. Penn Central Corporation
Lead Case No. CV-20-939184
Rosenfeld Deposition 8-27-2023

In the Circuit Court of Jackson County Missouri at Kansas City
Timothy Dalsing vs. BNSF
Case No. No. 2216-cv06539
Rosenfeld Deposition 7-28-2023

In the United States District Court for the Southern District of Texas Houston Division
International Terminals Company LLC Deer Park Fire Litigation
Lead Case No. 4:19-cv-01460
Rosenfeld Deposition 7-25-2023

In the Circuit Court of Livingston County Missouri
Shirley Ralls vs. Canadian Pacific Railway and Soo Lind Railroad
Case No. 28LV-CV0020
Rosenfeld Daubert Hearing 7-18-2023 Trial Testimony 7-19-2023

In the Circuit Court of Cook County Illinois
Brenda Wright vs. Penn Central and Conrail
Case No. No. 2032L003966
Rosenfeld Deposition 6-13-2023

In the Circuit Court Common Please Philadelphia of Jefferson County Alabama
Frank Belle vs. Birmingham Southern Railroad Company et al.
Case No. 01-cv-2021-900901.00
Rosenfeld Deposition 4-6-2023

In the Circuit Court of Jefferson County Alabama
Linda De Gregorio vs. Penn Central
Case No. 002278
Rosenfeld Deposition 3-27-20203

In the United States District Court Eastern District of New York
Rosalie Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-16-2023

In the Superior Court of Washington, Spokane County
Judy Cundy vs. BNSF
Case No. 21-2-03718-32
Rosenfeld Deposition 3-9-2023

In The Court of Common Pleas of Philadelphia County, PA Civil Trial Division
Feaster v Conrail
Case No. 001075
Rosenfeld Deposition 2-1-2023

In United States District Court for the Central District of Illinois
Sherman vs. BNSF
Case No. 3:17-cv-01192
Rosenfeld Deposition 1-18-2023

In United States District Court District of Colorado
Gonzales vs. BNSF
Case No. 1:21-cv-01690
Rosenfeld Deposition 1-17-2023

In United States District Court District of Colorado
Abeyta vs. BNSF
Case No. 1:21-cv-01689-KMT
Rosenfeld Deposition 1-3-2023

In United States District Court For The Easter District of Louisiana
Nathaniel Smith vs. Illinois Central Railroad
Case No. 2:21-cv-01235
Rosenfeld Deposition 11-30-2022

In the Superior Court of the State of California, County of San Bernardino
Billy Wildrick, Plaintiff vs. BNSF Railway Company
Case No. CIVDS1711810
Rosenfeld Deposition 10-17-2022

In the State Court of Bibb County, State of Georgia
Richard Hutcherson, Plaintiff vs Norfolk Southern Railway Company
Case No. 10-SCCV-092007
Rosenfeld Deposition 10-6-2022

In the Civil District Court of the Parish of Orleans, State of Louisiana
Millard Clark, Plaintiff vs. Dixie Carriers, Inc. et al.
Case No. 2020-03891
Rosenfeld Deposition 9-15-2022

In The Circuit Court of Livingston County, State of Missouri, Circuit Civil Division
Shirley Ralls, Plaintiff vs. Canadian Pacific Railway and Soo Line Railroad
Case No. 18-LV-CC0020
Rosenfeld Deposition 9-7-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jonny C. Daniels, Plaintiff vs. CSX Transportation Inc.
Case No. 20-CA-5502

Rosenfeld Deposition 9-1-2022

In The Circuit Court of St. Louis County, State of Missouri
Kieth Luke et. al. Plaintiff vs. Monsanto Company et. al.
Case No. 19SL-CC03191
Rosenfeld Deposition 8-25-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jeffery S. Lamotte, Plaintiff vs. CSX Transportation Inc.
Case No. NO. 20-CA-0049
Rosenfeld Deposition 8-22-2022

In State of Minnesota District Court, County of St. Louis Sixth Judicial District
Greg Bean, Plaintiff vs. Soo Line Railroad Company
Case No. 69-DU-CV-21-760
Rosenfeld Deposition 8-17-2022

In United States District Court Western District of Washington at Tacoma, Washington
John D. Fitzgerald Plaintiff vs. BNSF
Case No. 3:21-cv-05288-RJB
Rosenfeld Deposition 8-11-2022

In Circuit Court of the Sixth Judicial Circuit, Macon Illinois
Rocky Bennyhoff Plaintiff vs. Norfolk Southern
Case No. 20-L-56
Rosenfeld Deposition 8-3-2022, Trial 1-10-2023

In Court of Common Pleas, Hamilton County Ohio
Joe Briggins Plaintiff vs. CSX
Case No. A2004464
Rosenfeld Deposition 6-17-2022

In the Superior Court of the State of California, County of Kern
George LaFazia vs. BNSF Railway Company.
Case No. BCV-19-103087
Rosenfeld Deposition 5-17-2022

In the Circuit Court of Cook County Illinois
Bobby Earles vs. Penn Central et. al.
Case No. 2020-L-000550
Rosenfeld Deposition 4-16-2022

In United States District Court Easter District of Florida
Albert Hartman Plaintiff vs. Illinois Central
Case No. 2:20-cv-1633
Rosenfeld Deposition 4-4-2022

In the Circuit Court of the 4th Judicial Circuit, in and For Duval County, Florida
Barbara Steele vs. CSX Transportation
Case No.16-219-Ca-008796
Rosenfeld Deposition 3-15-2022

In United States District Court Easter District of New York
Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-10-2022

In the Circuit Court of Cook County Illinois
Linda Benjamin vs. Illinois Central
Case No. No. 2019 L 007599
Rosenfeld Deposition 1-26-2022

In the Circuit Court of Cook County Illinois
Donald Smith vs. Illinois Central
Case No. No. 2019 L 003426
Rosenfeld Deposition 1-24-2022

In the Circuit Court of Cook County Illinois
Jan Holeman vs. BNSF
Case No. 2019 L 000675
Rosenfeld Deposition 1-18-2022

In the State Court of Bibb County State of Georgia
Dwayne B. Garrett vs. Norfolk Southern
Case No. 20-SCCV-091232
Rosenfeld Deposition 11-10-2021

In the Circuit Court of Cook County Illinois
Joseph Ruepke vs. BNSF
Case No. 2019 L 007730
Rosenfeld Deposition 11-5-2021

In the United States District Court For the District of Nebraska
Steven Gillett vs. BNSF
Case No. 4:20-cv-03120
Rosenfeld Deposition 10-28-2021

In the Montana Thirteenth District Court of Yellowstone County
James Eadus vs. Soo Line Railroad and BNSF
Case No. DV 19-1056
Rosenfeld Deposition 10-21-2021

In the Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al. vs Cerro Flow Products, Inc.
Case No. 0i9-L-2295
Rosenfeld Deposition 5-14-2021
Trial October 8-4-2021

In the Circuit Court of Cook County Illinois
Joseph Rafferty vs. Consolidated Rail Corporation and National Railroad Passenger Corporation d/b/a AMTRAK,
Case No. 18-L-6845
Rosenfeld Deposition 6-28-2021

In the United States District Court For the Northern District of Illinois
Theresa Romcoe vs. Northeast Illinois Regional Commuter Railroad Corporation d/b/a METRA Rail
Case No. 17-cv-8517
Rosenfeld Deposition 5-25-2021

In the Superior Court of the State of Arizona In and For the Cunty of Maricopa
Mary Tryon et al. vs. The City of Pheonix v. Cox Cactus Farm, L.L.C., Utah Shelter Systems, Inc.
Case No. CV20127-094749

Rosenfeld Deposition 5-7-2021

In the United States District Court for the Eastern District of Texas Beaumont Division
Robinson, Jeremy et al vs. CNA Insurance Company et al.
Case No. 1:17-cv-000508
Rosenfeld Deposition 3-25-2021

In the Superior Court of the State of California, County of San Bernardino
Gary Garner, Personal Representative for the Estate of Melvin Garner vs. BNSF Railway Company.
Case No. 1720288
Rosenfeld Deposition 2-23-2021

In the Superior Court of the State of California, County of Los Angeles, Spring Street Courthouse
Benny M Rodriguez vs. Union Pacific Railroad, A Corporation, et al.
Case No. 18STCV01162
Rosenfeld Deposition 12-23-2020

In the Circuit Court of Jackson County, Missouri
Karen Cornwell, Plaintiff, vs. Marathon Petroleum, LP, Defendant.
Case No. 1716-CV10006
Rosenfeld Deposition 8-30-2019

In the United States District Court For The District of New Jersey
Duarte et al, Plaintiffs, vs. United States Metals Refining Company et. al. Defendant.
Case No. 2:17-cv-01624-ES-SCM
Rosenfeld Deposition 6-7-2019

In the United States District Court of Southern District of Texas Galveston Division
M/T Carla Maersk vs. Conti 168., Schiffahrts-GMBH & Co. Bulker KG MS "Conti Perdido" Defendant.
Case No. 3:15-CV-00106 consolidated with 3:15-CV-00237
Rosenfeld Deposition 5-9-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
Carole-Taddeo-Bates et al., vs. Ifran Khan et al., Defendants
Case No. BC615636
Rosenfeld Deposition 1-26-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
The San Gabriel Valley Council of Governments et al. vs El Adobe Apts. Inc. et al., Defendants
Case No.  BC646857
Rosenfeld Deposition 10-6-2018; Trial 3-7-19

In United States District Court For The District of Colorado
Bells et al. Plaintiffs vs. The 3M Company et al., Defendants
Case No. 1:16-cv-02531-RBJ
Rosenfeld Deposition 3-15-2018 and 4-3-2018

In The District Court Of Regan County, Texas, 112th Judicial District
Phillip Bales et al., Plaintiff vs. Dow Agrosciences, LLC, et al., Defendants
Cause No. 1923
Rosenfeld Deposition 11-17-2017

In The Superior Court of the State of California In And For The County Of Contra Costa
Simons et al., Plaintifs vs. Chevron Corporation, et al., Defendants
Cause No. C12-01481
Rosenfeld Deposition 11-20-2017

In The Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al., Plaintiff vs. Cerro Flow Products, Inc., Defendants
Case No.: No. 0i9-L-2295
Rosenfeld Deposition 8-23-2017

In United States District Court For The Southern District of Mississippi
Guy Manuel vs. The BP Exploration et al., Defendants
Case No. 1:19-cv-00315-RHW
Rosenfeld Deposition 4-22-2020

In The Superior Court of the State of California, For The County of Los Angeles
Warrn Gilbert and Penny Gilber, Plaintiff vs. BMW of North America LLC
Case No. LC102019 (c/w BC582154)
Rosenfeld Deposition 8-16-2017, Trail 8-28-2018

In the Northern District Court of Mississippi, Greenville Division
Brenda J. Cooper, et al., Plaintiffs, vs. Meritor Inc., et al., Defendants
Case No. 4:16-cv-52-DMB-JVM
Rosenfeld Deposition July 2017

In The Superior Court of the State of Washington, County of Snohomish
Michael Davis and Julie Davis et al., Plaintiff vs. Cedar Grove Composting Inc., Defendants
Case No. 13-2-03987-5
Rosenfeld Deposition, February 2017
Trial March 2017

In The Superior Court of the State of California, County of Alameda
Charles Spain., Plaintiff vs. Thermo Fisher Scientific, et al., Defendants
Case No. RG14711115
Rosenfeld Deposition September 2015

In The Iowa District Court In And For Poweshiek County
Russell D. Winburn, et al., Plaintiffs vs. Doug Hoksbergen, et al., Defendants
Case No. LALA002187
Rosenfeld Deposition August 2015

In The Circuit Court of Ohio County, West Virginia
Robert Andrews, et al. v. Antero, et al.
Civil Action No. 14-C-30000
Rosenfeld Deposition June 2015

In The Iowa District Court for Muscatine County
Laurie Freeman et. al. Plaintiffs vs. Grain Processing Corporation, Defendant
Case No. 4980
Rosenfeld Deposition May 2015

In the Circuit Court of the 17th Judicial Circuit, in and For Broward County, Florida
Walter Hinton, et. al. Plaintiff, vs. City of Fort Lauderdale, Florida, a Municipality, Defendant.
Case No. CACE07030358 (26)
Rosenfeld Deposition December 2014

In the County Court of Dallas County Texas
Lisa Parr et al, Plaintiff, vs. Aruba et al, Defendant.
Case No. cc-11-01650-E
Rosenfeld Deposition: March and September 2013

Rosenfeld Trial April 2014

In the Court of Common Pleas of Tuscarawas County Ohio
John Michael Abicht, et al., Plaintiffs, vs. Republic Services, Inc., et al., Defendants
Case No. 2008 CT 10 0741 (Cons. w/ 2009 CV 10 0987)
Rosenfeld Deposition October 2012

In the United States District Court for the Middle District of Alabama, Northern Division
James K. Benefield, et al., Plaintiffs, vs. International Paper Company, Defendant.
Civil Action No. 2:09-cv-232-WHA-TFM
Rosenfeld Deposition July 2010, June 2011

In the Circuit Court of Jefferson County Alabama
Jaeanette Moss Anthony, et al., Plaintiffs, vs. Drummond Company Inc., et al., Defendants
Civil Action No. CV 2008-2076
Rosenfeld Deposition September 2010

In the United States District Court, Western District Lafayette Division
Ackle et al., Plaintiffs, vs. Citgo Petroleum Corporation, et al., Defendants.
Case No. 2:07CV1052
Rosenfeld Deposition July 2009

# ATTACHMENT C

**Aaron Smith**
Department of Agricultural and Resource Economics

# Cow Poop is Now a Big Part of California Fuel Policy

## Are the state's new low-carbon fuel regulations full of BS?

by Aaron David Smith | January 22, 2024

Every day, California farmers milk 1.7 million cows. Each cow generates about 7 gallons of milk and 100 gallons of waste. Most farmers process the waste (mostly manure) by washing it into lagoons where microbes break it down and, in the process, emit methane, a potent greenhouse gas.

These facts raise two questions. First, can we prevent the manure-eating microbes from sending methane into the atmosphere? Second, can we capture the methane and use it for energy?

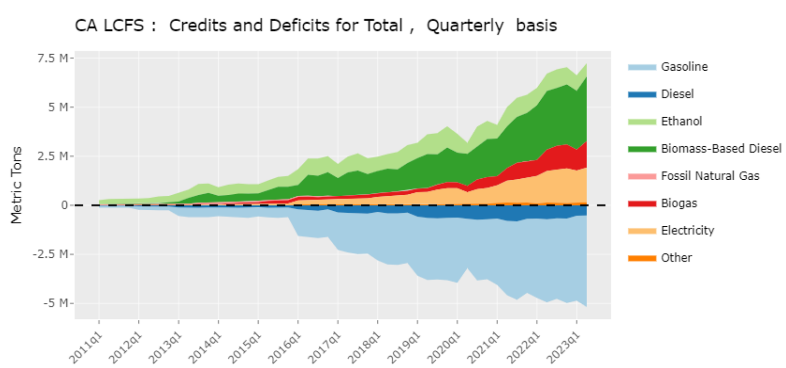
California has answered yes to both questions. On the first question, it aims to reduce methane emissions from livestock manure by 40% below 2013 levels by 2030 (codified in SB 1383). One way to achieve this goal would be to place the burden on farmers by charging them a methane emissions fee or requiring them to use practices or technologies that reduce methane emissions. This approach would raise the cost of producing milk and therefore increase the price consumers pay for dairy products. The cost increase may cause some farmers to move out of state, taking their methane emissions with them. This response, known as leakage, arises in many environmental policies, including in California's cap and trade program, as explained by Meredith in this blog.

California has chosen a different path. It has shoehorned dairy methane into a transportation program: the low carbon fuel standard (LCFS). This structure avoids leakage, but it makes consumers and producers of gasoline and diesel pay for reductions in dairy manure emissions.

**Manure in the LCFS**

To capture methane from manure lagoons, farmers install anaerobic digesters, which are essentially giant covers that seal manure in the lagoon to keep oxygen out while microbes feed on the contents. The captured methane — known as biogas — is then cleaned and injected into a natural gas pipeline, from which it has multiple uses including fueling a natural-gas powered vehicle and generating electricity.

This dairy biogas earns LCFS credits because it is considered a low carbon fuel. The LCFS sets a target for the average carbon intensity of transportation fuels consumed in the state. Fuels that are more carbon intensive than the target accrue deficits that must be balanced by credits earned by fuels that are less carbon intensive. The figure below shows that gasoline and diesel producers generate deficits, which they can offset by buying credits from producers of biogas and other lower-GHG fuels like electricity and renewable diesel.




*Source: Our LCFS Data App. Click to view and download data using your web browser.*

In the most recent LCFS data, dairy biogas contributed almost 20% of the credits in the LCFS program, yet it provided less than 1% of energy used for transportation. Dairy biogas has an outsized impact in the LCFS because it is treated very differently than most fuels. Last month's proposed LCFS amendments indicate that this differential treatment will continue.

**The LCFS Assigns Dairy Biogas a Large Negative Carbon Intensity**

Carbon intensity is the number of grams of carbon dioxide emissions produced per megajoule of energy. The California Air Resources Board (CARB) calculates this number for each fuel source using a life cycle analysis that accounts for tailpipe emissions as well as potential emissions throughout the fuel production process. For example, petroleum gasoline has a carbon intensity of 100.82 and an electric car powered by solar-generated electricity has a carbon intensity of zero. Most other fuels have carbon intensities between zero and 100.

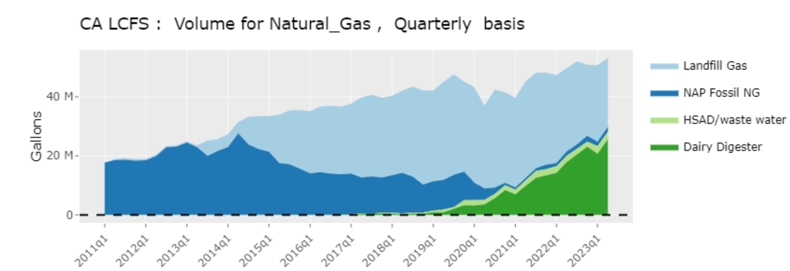
The carbon intensity of dairy biogas ranges between -102.79 and -790.41 depending on characteristics of the digester. The current average carbon intensity for dairy biogas is -269.

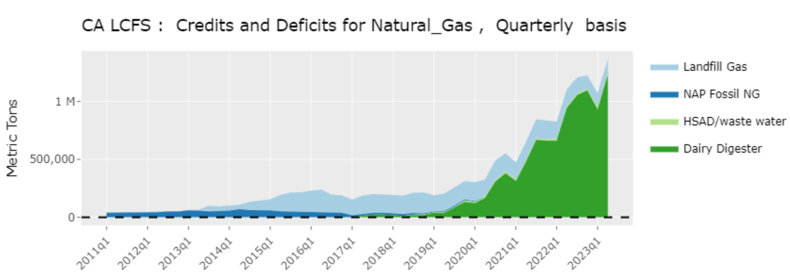
CARB assigns dairy biogas a negative carbon intensity because it gives credit for preventing methane emissions that would otherwise have occurred. Their argument is that, if a farmer had not installed a digester on a manure lagoon, then it would have sent methane into the atmosphere.

Microbes produce different amounts of gas inside a digester than they would in an open lagoon because of differing environmental factors such as oxygen exposure and temperature. The carbon intensity number is determined by the estimated emissions from the open lagoon (avoided methane) per unit of biogas produced. For example, in highly productive digesters, the amount of prevented methane is low as a proportion of the biogas produced, so such a digester would get a relatively small negative carbon intensity.

In the LCFS, fuels with a negative carbon intensity are very helpful in meeting the policy target because they can offset a lot of high-carbon fuel. For example, adding one average biogas-powered vehicle to the fleet would produce enough LCFS credits to cover the deficits incurred by 26 similar gasoline-powered vehicles.

This accounting scheme is one reason why dairy biogas has increased from almost non-existent five years ago to half of all natural gas used for transportation in the state. The other half is contributed by biogas captured from landfills. However, landfill gas gets a carbon intensity of 53 because it does not get credit for avoided-methane emissions. So, even though its fuel volumes are similar to dairy, it generates only a fraction of the credits, as shown in the figure below. Biogas can also earn LCFS credits by generating hydrogen or electricity for use in transportation, but these pathways have been used very little so far.



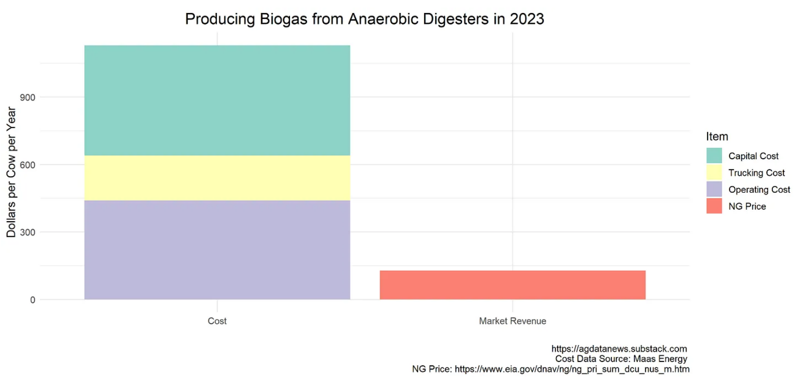

*Source: Our LCFS Data App. Click to view and download data using your web browser.*

### Costs and Benefits of Anaerobic Digesters

In this 2023 blog, I showed that the cost of an anaerobic digester is about 10 times the market value of the gas it produces. A representative new digester costs about about $1130 per milking cow per year, comprising $490 in capital costs and $440 in operating costs, plus $200 in trucking costs if unable to connect directly to a gas pipeline. In 2023, revenue from selling gas was about $128, for a net cost of about $1000 per milking cow per year. This representative digester has a carbon intensity of -355, which corresponds to about 6 metric tons of CO2 equivalent emissions per milking cow per year.

So, for $1000 we reduce CO2 emissions by 6 metric tons, or $167 per ton.

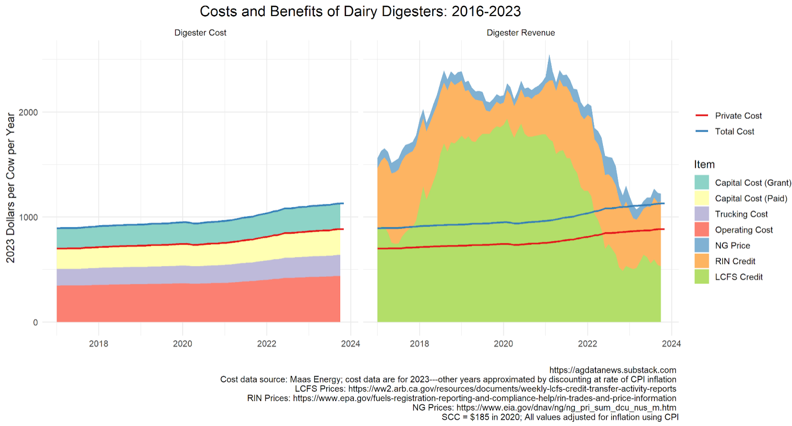
Methane is a far more powerful greenhouse gas than CO2, but it doesn't last nearly as long in the atmosphere. There is a vigorous scientific debate over how best to convert methane emissions into CO2 equivalent accounting for both how much it warms and when. Using an alternative approach would reduce the estimated emissions reduction by a factor of three and therefore raise the cost per ton by a factor of three. Moreover, all these numbers assume that CARB correctly estimates the amount of prevented emissions.




### Incentives Facing Farmers

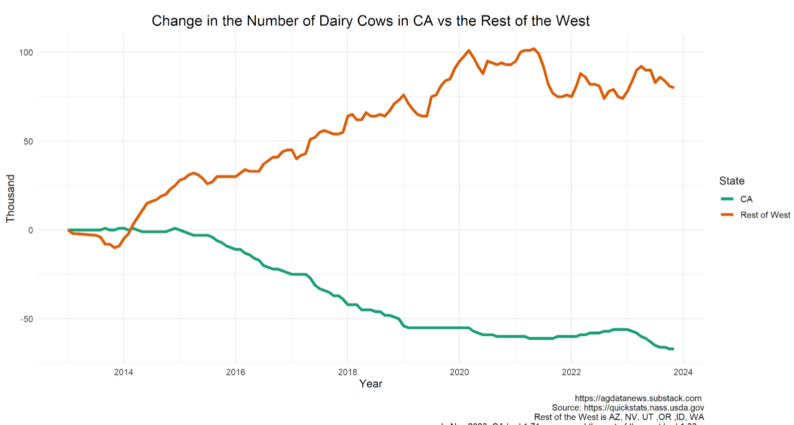
Anaerobic digesters receive government support through three programs. First, using proceeds from the state's cap and trade program, the California Department of Food and Agriculture offers grants to cover up to half the capital costs of building digesters. Second, sellers of dairy biogas generate credits in the federal renewable fuel standard (known as RINs). Third, they earn LCFS credits.

Between mid 2018 and the end of 2021, revenues from selling biogas and the associated RIN and LCFS credits were approximately double the cost of installing and running a typical digester, as shown in the figure below. LCFS credit prices have declined in the last two years, making the typical digester closer to a break even proposition. If and when credit prices go back up, then the profits will return.




High profits from operating digesters create the incentive for farmers to expand dairy herds for the purpose of generating manure rather than for producing milk. Between 2014 and 2019, California dairy cow numbers declined by 50,000 while the number of cows in other western states increased by 100,000 (see figure below). Since 2019, cow numbers have been relatively flat throughout the west.

It is possible that the advent of digesters in California stemmed the flow of cows out of the state. Dairy farmers outside California can access only two of the three digester programs accessible to California farmers. They are eligible to earn LCFS and RIN credits for their biogas, but they cannot receive California Department of Food and Agriculture grants to cover capital costs. Whether this grant funding is the difference between leaving and staying in California is an important topic for further research given the potential for emissions leakage if the state were to remove negative crediting but still require farmers to reduce manure methane emissions as per SB 1383.




### What Next?

CARB is proposing several amendments to the LCFS. It considered removing the negative crediting of dairy biogas projects, but its proposal (which is currently out for comment) opted to continue negative credits until 2040 for biogas used directly in transportation and until 2045 for biogas used to produce hydrogen for transportation.

There is a long tradition in agriculture of governments paying farmers for environmental improvement, rather than placing the burden on farmers to make those improvements. As a result, consumers do not see the full cost to society of the food they eat. Instead, those costs are shifted to taxpayers or, in the case of dairy biogas, gasoline and diesel consumers. Such mispricing can cause costly misallocations of resources, as articulated often on this blog.

Leakage is the main argument given for continuing negative crediting. There are several ways to mitigate leakage. Some, such as border adjustments (tax dairy products coming into California) would be very difficult to operationalize. A good rule in policy is to directly target the problem you are trying to solve. In this case, the problem would be methane-mitigation costs imposed on farmers that cause them to move out of state. Negative crediting in the LCFS is a convoluted solution with numerous drawbacks. A direct solution could involve the state sharing the costs of methane mitigation practices, which they already do to some extent through California Department of Food and Agriculture programs.

I made the last three figures using this R code. This article is cross posted at the Energy Institute blog.

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# ATTACHMENT D

## Table 17. **Milk Cow Herd Size by Inventory and Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

| Milk cow herd | Cattle and calves inventory | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Total | | Cows and heifers that calved | | Milk cows | | Other cattle (see text) | |
| | Farms | Number | Farms | Number | Farms | Number | Farms | Number |
| Farms with December 31, 2017 milk cow herd size of- | | | | | | | | |
| 1 to 9 | 380 | 20,704 | 380 | 11,584 | 380 | 767 | 237 | 9,120 |
| 10 to 19 | 26 | 1,307 | 26 | 767 | 26 | 306 | 17 | 540 |
| 20 to 49 | 32 | 2,009 | 32 | 1,467 | 32 | 919 | 22 | 542 |
| 50 to 99 | 20 | 3,102 | 20 | 1,971 | 20 | 1,467 | 14 | 1,131 |
| 100 to 199 | 62 | 23,398 | 62 | 15,780 | 62 | 9,209 | 55 | 7,618 |
| 200 to 499 | 249 | 139,592 | 249 | 83,919 | 249 | 81,452 | 231 | 55,673 |
| 500 to 999 | 296 | 368,808 | 296 | 211,922 | 296 | 209,626 | 278 | 156,886 |
| 1,000 to 2,499 | 390 | 1,117,162 | 390 | 648,456 | 390 | 638,080 | 369 | 468,706 |
| 2,500 to 4,999 | 163 | 988,072 | 163 | 550,937 | 163 | 546,617 | 154 | 437,135 |
| 5,000 or more | 35 | 460,469 | 35 | 262,482 | 35 | 261,886 | 35 | 197,987 |
| All farms with December 31, 2017 milk cow inventory | 1,653 | 3,124,623 | 1,653 | 1,789,285 | 1,653 | 1,750,329 | 1,412 | 1,335,338 |
| Farms with no milk cow inventory, on December 31, 2017 | 12,041 | 2,060,970 | 9,889 | 643,416 | - | - | 9,312 | 1,417,554 |
| Total | 13,694 | 5,185,593 | 11,542 | 2,432,701 | 1,653 | 1,750,329 | 10,724 | 2,752,892 |

| Milk cow herd | Cattle and calves sales | | | | | | | Milk sales | |
|---|---|---|---|---|---|---|---|---|---|
| | Total | | | Cattle | | Calves | | | |
| | Farms | Number | Value ($1,000) | Farms | Number | Farms | Number | Farms | Value ($1,000) |
| Farms with December 31, 2017 milk cow herd size of- | | | | | | | | | |
| 1 to 9 | 203 | (D) | 21,310 | 170 | (D) | 94 | (D) | 24 | 176 |
| 10 to 19 | 19 | (D) | 727 | 17 | 511 | 10 | (D) | 14 | 693 |
| 20 to 49 | 31 | 1,456 | 1,406 | 31 | 1,312 | 11 | 144 | 31 | 3,384 |
| 50 to 99 | 20 | 1,190 | 985 | 20 | 834 | 14 | 356 | 17 | 5,040 |
| 100 to 199 | 62 | 9,566 | 7,206 | 62 | (D) | 45 | (D) | 60 | 30,513 |
| 200 to 499 | 239 | 50,907 | 36,800 | 237 | 28,036 | 183 | 22,871 | 249 | 324,622 |
| 500 to 999 | 293 | 109,999 | 73,414 | 292 | (D) | 230 | (D) | 296 | 829,287 |
| 1,000 to 2,499 | 381 | 383,639 | 245,585 | 371 | 185,095 | 321 | 198,544 | 390 | 2,385,176 |
| 2,500 to 4,999 | 160 | 350,862 | 250,365 | 158 | 184,466 | 130 | 166,396 | 163 | 1,967,972 |
| 5,000 or more | 35 | 159,363 | 109,542 | 35 | 75,054 | 31 | 84,309 | 35 | 930,481 |
| All farms with December 31, 2017 milk cow inventory | 1,443 | 1,113,851 | 747,339 | 1,393 | 540,348 | 1,069 | 573,503 | 1,279 | 6,477,344 |
| Farms with no milk cow inventory, on December 31, 2017 | 8,824 | 1,959,243 | 2,364,071 | 8,037 | 1,584,184 | 3,340 | 375,059 | 8 | 5,786 |
| Total | 10,267 | 3,073,094 | 3,111,410 | 9,430 | 2,124,532 | 4,409 | 948,562 | 1,287 | 6,483,130 |

## Table 18. **Cattle and Calves - Number Sold Per Farm by Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

| Number sold | Cattle and calves | | | Cattle weighing 500 pounds or more (see text) | | Calves weighing less than 500 pounds | |
|---|---|---|---|---|---|---|---|
| | Farms | Number | Value ($1,000) | Farms | Number | Farms | Number |
| Total | 10,267 | 3,073,094 | 3,111,410 | 9,430 | 2,124,532 | 4,409 | 948,562 |
| Farms by number of cattle and calves sold- | | | | | | | |
| 1 to 9 | 3,827 | 14,605 | 13,069 | 3,248 | 11,123 | 1,162 | 3,482 |
| 10 to 19 | 1,412 | 19,160 | 16,763 | 1,281 | 14,768 | 584 | 4,392 |
| 20 to 49 | 1,676 | 51,749 | 46,295 | 1,597 | 40,129 | 751 | 11,620 |
| 50 to 99 | 962 | 65,444 | 59,774 | 944 | 51,723 | 464 | 13,721 |
| 100 to 199 | 679 | 93,740 | 85,099 | 670 | 73,331 | 354 | 20,409 |
| 200 to 499 | 789 | 248,298 | 219,850 | 786 | 180,952 | 458 | 67,346 |
| 500 to 999 | 409 | 287,144 | 239,514 | 397 | 185,674 | 267 | 101,470 |
| 1,000 to 2,499 | 350 | 543,513 | 404,769 | 349 | 329,495 | 258 | 214,018 |
| 2,500 or more | 163 | 1,749,441 | 2,026,277 | 158 | 1,237,337 | 111 | 512,104 |

## Table 19. **Hogs and Pigs - Inventory: 2017 and 2012**

[For meaning of abbreviations and symbols, see introductory text.]

| Hogs and pigs | 2017 | | 2012 | |
|---|---|---|---|---|
| | Farms | Number | Farms | Number |
| Total hogs and pigs | 1,389 | 96,456 | 1,437 | 111,893 |
| Farms with - | | | | |
| 1 to 24 | 1,191 | 6,804 | 1,228 | 6,370 |
| 25 to 49 | 102 | 3,397 | 95 | 3,117 |
| 50 to 99 | 42 | 2,587 | 52 | 3,446 |
| 100 to 199 | 24 | 2,949 | 39 | 5,041 |
| 200 to 499 | 17 | 5,173 | 11 | 3,626 |
| Total hogs and pigs - Con. | | | | |
| Farms with - - Con. | | | | |
| 500 to 999 | 4 | 2,602 | 4 | 2,570 |
| 1,000 to 1,999 | 5 | (D) | 4 | (D) |
| 2,000 to 4,999 | 3 | 7,720 | 2 | (D) |
| 5,000 or more | 1 | (D) | 2 | (D) |

## Table 17. **Milk Cow Herd Size by Inventory and Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

| Milk cow herd | Cattle and calves inventory | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Total | | Cows and heifers that calved | | Milk cows | | Other cattle | |
| | Farms | Number | Farms | Number | Farms | Number | Farms | Number |
| Farms with December 31, 2022 milk cow herd size of- | | | | | | | | |
| 1 to 9 | 256 | 2,675 | 256 | 1,686 | 256 | 549 | 142 | 989 |
| 10 to 19 | 20 | 634 | 20 | 474 | 20 | 221 | 10 | 160 |
| 20 to 49 | 9 | 474 | 9 | 300 | 9 | 247 | 6 | 174 |
| 50 to 99 | 10 | 1,379 | 10 | 949 | 10 | 739 | 6 | 430 |
| 100 to 199 | 20 | 6,352 | 20 | 3,907 | 20 | 2,947 | 18 | 2,445 |
| 200 to 499 | 79 | 46,997 | 79 | 28,378 | 79 | 25,889 | 75 | 18,619 |
| 500 to 999 | 153 | 207,253 | 153 | 117,051 | 153 | 113,880 | 149 | 90,202 |
| 1,000 to 2,499 | 315 | 909,087 | 315 | 525,903 | 315 | 518,014 | 304 | 383,184 |
| 2,500 or more | 255 | 1,857,818 | 255 | 1,033,210 | 255 | 1,025,716 | 254 | 824,608 |
| All farms with December 31, 2022 milk cow inventory | 1,117 | 3,032,669 | 1,117 | 1,711,858 | 1,117 | 1,688,202 | 964 | 1,320,811 |
| Farms with no milk cow inventory, on December 31, 2022 | 10,642 | 2,206,401 | 9,058 | 658,364 | - | - | 8,274 | 1,548,037 |
| Total | 11,759 | 5,239,070 | 10,175 | 2,370,222 | 1,117 | 1,688,202 | 9,238 | 2,868,848 |

| Milk cow herd | Cattle and calves sales | | | | | | | Milk sales | |
|---|---|---|---|---|---|---|---|---|---|
| | Total | | | Cattle | | Calves | | | |
| | Farms | Number | ($1,000) | Farms | Number | Farms | Number | Farms | ($1,000) |
| Farms with December 31, 2022 milk cow herd size of- | | | | | | | | | |
| 1 to 9 | 113 | 947 | 950 | 91 | 703 | 44 | 244 | 7 | 49 |
| 10 to 19 | 16 | 2,240 | (D) | 14 | (D) | 14 | (D) | 4 | (D) |
| 20 to 49 | 8 | 394 | (D) | 7 | (D) | 5 | (D) | 7 | 1,303 |
| 50 to 99 | 10 | 919 | 918 | 10 | 633 | 8 | 286 | 10 | 4,256 |
| 100 to 199 | 20 | 2,318 | 2,345 | 19 | 1,568 | 13 | 750 | 20 | 16,207 |
| 200 to 499 | 79 | 18,132 | 16,040 | 79 | 10,253 | 58 | 7,879 | 79 | 149,465 |
| 500 to 999 | 153 | 68,727 | 55,500 | 153 | 34,030 | 129 | 34,697 | 153 | 677,867 |
| 1,000 to 2,499 | 315 | 362,613 | 285,505 | 315 | 171,601 | 277 | 191,012 | 315 | 3,083,205 |
| 2,500 or more | 255 | 759,699 | 614,433 | 255 | 363,648 | 232 | 396,051 | 255 | 5,733,317 |
| All farms with December 31, 2022 milk cow inventory | 969 | 1,215,989 | 978,668 | 943 | 584,534 | 780 | 631,455 | 850 | (D) |
| Farms with no milk cow inventory, on December 31, 2022 | 7,574 | 2,158,354 | 2,745,144 | 7,041 | 1,716,066 | 3,189 | 442,288 | 5 | (D) |
| Total | 8,543 | 3,374,343 | 3,723,812 | 7,984 | 2,300,600 | 3,969 | 1,073,743 | 855 | 9,675,301 |

## Table 18. **Cattle and Calves - Number Sold per Farm by Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

| Number sold | Cattle and calves | | | Cattle weighing 500 pounds or more | | Calves weighing less than 500 pounds | |
|---|---|---|---|---|---|---|---|
| | Farms | Number | Value ($1,000) | Farms | Number | Farms | Number |
| Total | 8,543 | 3,374,343 | 3,723,812 | 7,984 | 2,300,600 | 3,969 | 1,073,743 |
| Farms by number of cattle and calves sold- | | | | | | | |
| 1 to 9 | 3,004 | 11,780 | 11,174 | 2,562 | 8,911 | 938 | 2,869 |
| 10 to 19 | 1,088 | 14,487 | 13,647 | 1,012 | 11,161 | 469 | 3,326 |
| 20 to 49 | 1,460 | 44,805 | 42,102 | 1,438 | 33,330 | 733 | 11,475 |
| 50 to 99 | 767 | 52,773 | 52,539 | 761 | 40,178 | 409 | 12,595 |
| 100 to 199 | 614 | 84,987 | 84,399 | 611 | 67,048 | 316 | 17,939 |
| 200 to 499 | 666 | 204,620 | 204,669 | 666 | 154,158 | 390 | 50,462 |
| 500 to 999 | 351 | 245,642 | 227,405 | 351 | 171,526 | 237 | 74,116 |
| 1,000 to 2,499 | 344 | 552,451 | 479,768 | 344 | 311,896 | 291 | 240,555 |
| 2,500 or more | 249 | 2,162,798 | 2,608,109 | 239 | 1,502,392 | 186 | 660,406 |

## Table 19. **Hogs and Pigs - Inventory: 2022 and 2017**

[For meaning of abbreviations and symbols, see introductory text.]

| Hogs and pigs | 2022 | | 2017 | |
|---|---|---|---|---|
| | Farms | Number | Farms | Number |
| Total hogs and pigs | 1,374 | 82,010 | 1,389 | 96,456 |
| Farms with- | | | | |
| 1 to 24 | 1,157 | 7,121 | 1,191 | 6,804 |
| 25 to 49 | 110 | 3,745 | 102 | 3,397 |
| 50 to 99 | 52 | 3,153 | 42 | 2,587 |
| 100 to 199 | 24 | 3,339 | 24 | 2,949 |
| 200 to 499 | 22 | 5,298 | 17 | 5,173 |
| Total hogs and pigs - Con. | | | | |
| Farms with- - Con. | | | | |
| 500 to 999 | 3 | 2,343 | 4 | 2,602 |
| 1,000 to 1,999 | 2 | (D) | 5 | (D) |
| 2,000 to 4,999 | 2 | (D) | 3 | 7,720 |
| 5,000 or more | 2 | (D) | 1 | (D) |

# ATTACHMENT E

Briefing Paper

# FACTORY FARM DAIRIES, BIOGAS, AND THE DANGEROUS PATH CALIFORNIA IS ON

## I. INTRODUCTION

Industrial dairies in the San Joaquin Valley, packing thousands, and sometimes tens of thousands of cows into a single facility, are a major source of local air and water pollution, nuisance odor, groundwater overdraft, and greenhouse gas emissions. Over the last decade, California has created a regulatory landscape that pays this industry to continue these polluting practices while producing factory farm gas, otherwise known as dairy biogas. These policies favor large-scale industrial dairies over smaller operations and lock in the most environmentally harmful industry practices that disproportionately harm low-income communities of color. And these policies actually *encourage dairies to create* methane and only *appear* to succeed in achieving massive greenhouse gas emissions reductions as a result of an overly narrow life cycle analysis for the fuel's "well-to-wheel" climate impacts. The good news is that California can, and must, choose another path – one that aligns with our climate and environmental health and equity objectives.

## II. BACKGROUND – THE EVOLUTION OF MASSIVE DAIRIES IN THE SAN JOAQUIN VALLEY DESPITE KNOWN CLIMATE AND ENVIRONMENTAL IMPACTS WAS A POLICY CHOICE

The expansion and concentration of the California dairy industry over the last several decades has occurred with policymakers' knowledge of the industry's climate and community impacts. The California dairy sector in the 1950s milked about 800,000 cows on almost twenty thousand pasture-based farms. California land use and environmental policy allowed for the dairy industry to transition into gigantic, full confinement, industrial-style operations that liquefy and manage manure anaerobically in gigantic so-called lagoons. Now, the industry milks between 1.7 and 1.8 million cows on about 1,100 farms – the vast majority of which, and the largest of which are in the San Joaquin Valley.[1]

This shift to massive dairies concentrated in the San Joaquin Valley was a policy choice and business choice – it was neither accidental nor inevitable.

1 https://www.dairycares.com/post/keeping-cows-in-california-is-good-for-people-and-planet.

In the late 1990s, water quality regulators drove the relocation of the southern California dairy herd from the Chino Basin in San Bernardino County to the San Joaquin Valley when groundwater pollution from manure affected water quality. Rising housing costs in the Inland Empire produced a windfall for those dairies as they sold their land to developers and raced toward cheaper land – and fewer regulations – in the San Joaquin Valley. San Joaquin Valley counties welcomed those Chino-based dairy operators with open arms and authorized hundreds of new dairies and dairy expansions as the California dairy industry increased in size dramatically to over 1.8 million in 2008.[2] By 2008, there were about 1,900 dairy farms in California not only producing milk, but massive amounts of manure. For context, a 2,000 cow industrial dairy produces approximately the same amount of fecal waste as a city of one million people.[3] Many of the factory farms in the San Joaquin Valley are 3 to 5 times that size. Local county governments in the San Joaquin Valley supported this expansion as modern dairy operations overwhelmingly opted for liquefied manure management despite the known climate impacts from methane and known risks of groundwater contamination.[4] Local governments and the dairy operators themselves *knew* that the liquefied manure model of dairy production relied on an externalization of climate and adverse local pollution impacts, and adopted statements of overriding considerations to approve those projects despite "significant and unavoidable impacts" as allowed by the California Environmental Quality Act (CEQA). Several counties adopted land use policies that facilitated dairy citing and expansion while others allowed (and are continuing to allow) dairy expansions without requiring CEQA environmental review.

## III. MASSIVE DAIRIES HAVE SIGNIFICANT AND HARMFUL ENVIRONMENTAL IMPACTS

### A. Industrial Dairies Contribute to Dangerous Air Pollution

Dairies emit large amounts of volatile organic compounds (VOC), ammonia, nitrogen oxides (NOx), and dust which all contribute to extremely poor air quality in the San Joaquin Valley, a region out of compliance with state and federal air quality standards.

- VOCs are a precursor to ozone formation. The San Joaquin Valley has been designated as Extreme Nonattainment for EPA's 2008 8-hour ozone standard and 2012 8-hour ozone standard.[5] The San Joaquin Valley is also Severe Nonattainment for the state one hour ozone standard.[6] Dairies are the largest source of VOCs in the Valley.

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**2** *Id.*

**3** Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba. See: https://www.holsteinusa.com/pdf/fact_sheet_cattle.pdf. Also see: *The Characterization of Feces and Urine* (2015), available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4500995/.

**4** *See, e.g.* Kings County Dairy Element Program EIR at 4.2-83 to 4.2-85, available at https://www.countyofkings.com/home/showpublisheddocument/4358/635277478494870000 (last visited October 24, 2022).

**5** *Ambient Air Quality Standards and Valley Attainment Status*. Accessed January 9, 2022. Available at: https://www.valleyair.org/aqinfo/attainment.htm.

**6** *Id.*

- Dairies also emit significant amounts of ammonia, a PM2.5 precursor. Recent research estimates that 1,690 people die in California annually as a result of agricultural ammonia emissions because ammonia and NOx create ammonium nitrate, the most prevalent form of PM2.5 in the San Joaquin Valley. The Valley is Serious Nonattainment for the Federal 1997 annual, the 2006 24-hour, and the 2012 annual PM2.5 standards.[7] Dairies are the largest source of ammonia in the Valley.

- Dairies also emit large amounts of NOx from manure application on crop land, which contributes to increasing the ozone concentration and PM2.5.

**Both Ozone and PM2.5 result in serious and long lasting health impacts.** Ozone can trigger chest pain, coughing, throat irritation, congestion, worsen bronchitis, emphysema, and asthma. Ozone also can reduce lung function and inflame the lining of the lungs. PM2.5 can cause eye, nose, throat and lung irritation, coughing, sneezing, runny nose and shortness of breath. Both ozone and PM2.5 exposures are correlated to increases in hospitalization, emergency room visits, and premature death from cardiovascular and respiratory disease.

**In addition to PM2.5 and Ozone, dairies cause significant odors.** Many Californians glimpse the impacts when they drive through the San Joaquin Valley, catch a whiff of manure odors, and roll up the windows. However, for residents who live near these facilities, there is no driving away from these extreme odors. Even going inside their homes does not always provide respite. Residents report odors following them indoors, permeating their clothes, and causing headaches.

### B. Industrial Dairies Degrade Water Quality

With the average dairy cow producing approximately 148 pounds of manure each day,[8] California dairies contribute tens of millions of tons of manure each year. Untreated manure cannot be applied to crops for human consumption so there is limited acreage upon which manure may be applied. And there simply isn't enough. **Nitrate from manure leaches into groundwater and pollutes drinking water supplies**. Manure from lagoons, corrals, and, above all, applied to land leads to nitrate contamination.

The dairy industry's own report on nitrate pollution revealed the breadth and degree of groundwater contamination from dairies. The Central Valley Summary Representative Monitoring Report was prepared by the Central Valley Dairy Representative Monitoring Program, a nonprofit association of dairy owners and operators. It presents years of monitoring data from forty-two Central Valley dairies chosen to be representative of the industry in the region. Some findings of note:

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**7** See: https://www3.epa.gov/airquality/greenbook/knca.html#PM-2.5.2012.San_Joaquin_Valley.

**8** Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba.

- **Elevated nitrate-N (i.e., as nitrogen) concentrations were present beneath all monitored dairies.**[9]
- "...approximately 94 percent of nitrogen loading on dairies (that is, the portion of
- nitrogen that enters the soil and is not recovered by plants) occurs on cropland." [10]
- Dairies produce an "excess supply of nitrogen" in the form of manure than the amount that can be safely applied to cropland without causing or contributing to nitrate pollution.[11]

Larger, more concentrated herds mean more manure concentrated on the same or smaller land, thus exacerbating the issue of greater quantities of manure than cropland can absorb. A recent proposed dairy expansion in Merced notes that increased herd sizes (from under 3,000 to 7,300 cows) indicated in their environmental documents that manure exports would jump from about 9,000 tons to 49,000 tons annually. **No information was provided as to where that manure would be exported. Presumably, because there is nowhere for it to go.**

**Nitrates in drinking water cause blue baby syndrome and have been linked to cancer.**[12] The cost to treat drinking water – if treatment is even available – can make water bills unaffordable for many households and can be cost prohibitive for private well owners.

### C. Industrial Dairies Are Water Hogs

The San Joaquin Valley is ground zero for critical groundwater overdraft and water scarcity.[13] Thousands of private and community water wells, upon which many Californians rely for drinking water, have already run dry.[14] Overdraft also impacts water quality. As groundwater supply decreases, concentrations of contaminants, especially arsenic, increase.[15]

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9 CENTRAL VALLEY DAIRY REPRESENTATIVE MONITORING PROGRAM, SUMMARY REPRESENTATIVE MONITORING REPORT (REVISED*) at 6 (Apr. 19, 2019), https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_facilities/groundwater_monitoring/srmr_20190419.pdf.

10 *Id.* at 10.

11 *Id.*

12 Ward MH, Jones RR, Brender JD, de Kok TM, Weyer PJ, Nolan BT, Villanueva CM, van Breda SG. Drinking Water Nitrate and Human Health: An Updated Review. Int J Environ Res Public Health. 2018 Jul 23;15(7):1557. doi: 10.3390/ijerph15071557. PMID: 30041450; PMCID: PMC6068531.

13 Critically Overdrafted Basins, CAL. DEP'T OF WATER RES., https://water.ca.gov/programs/groundwater management/bulletin-118/critically-overdrafted-basins (last visited Mar. 22, 2022) (showing most groundwater basins and subbasins in the San Joaquin Valley are critically overdrafted); see ELLEN HANAK ET AL., WATER AND THE FUTURE OF THE SAN JOAQUIN VALLEY (2019), PUB. POL. INST. OF CAL., https://www.researchgate.net/publication/331476376_Water_and_the_Future_of_the_San_Joaquin_Valley.

14 Groundwater Management and Drought: An Interview with the San Joaquin Valley Partnership, CAL. DEP'T OF WATER RES., (Mar. 8, 2022), https://water.ca.gov/News/Blog/2022/March-22/Groundwater-Management-and-Drought-An-Interview-with-the-San-Joaquin-Valley-Partnership (noting that groundwater overdraft is causing domestic well owners to "lose access to their primary source of drinking water," leaving them unable to "afford or obtain services due to drilling backlogs or financial challenges" and forcing them to seek out and rely on emergency sources of drinking water); see Jelena Jezdimirovic et al., Will Groundwater Sustainability Plans End the Problem of Dry Drinking Water Wells?, PUB. POL'Y INST. OF CALIFORNIA (May 14, 2020), https://www.ppic.org/blog/will-groundwater-sustainability-plans-end-the-problem-of-dry-drinking-water-wells/.

15 See: https://environment-review.yale.edu/overpumping-california-groundwater-could-lead-dangerous-arsenic-water-and-food.

Industrial dairies use massive amounts of water including groundwater in the extremely fragile San Joaquin Valley ecosystem. In addition to supplying large amounts of drinking water to cows, dairies need large amounts of water for liquefying and flushing manure and other pollutants for storage in lagoons, cooling animals, cleaning facilities, and irrigating crops. In addition, dairies rely upon water-intensive crops to feed dairy cows such as alfalfa. California's large dairies use an estimated 142 million gallons per day,[16] or almost 52 billion gallons per year.

### D. Industrial Dairies Cause Dispoportionate Environmental Impacts

San Joaquin Valley residents are disproportionately Latino/a/e as compared to California as a whole. Seven central and southern San Joaquin Valley Counties (Kern to Stanislaus) have higher Latino/a/e populations than the state, with populations ranging from almost 50 percent to over 66 percent, as compared to the state population with 40 percent of residents classified as Latino/a/e. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[17] **Therefore, policies that entrench and exacerbate air and water pollution in these regions have a racially disparate impact on Latino/a/e communities.**

Similarly, San Joaquin Valley counties are lower income and have more residents facing economic insecurity than the state as a whole. While median household income in California is approximately $84,000 countywide household median incomes in the central and southern San Joaquin Valley Counties range from approximately $57,000 to $68,000 The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $59,000 and $57,000 , 70% or less of statewide median income. Poverty rates hover around 22% and 19% in Merced and Tulare, respectively.

## IV. FACTORY FARM GAS – AN INADEQUATE CLIMATE SOLUTION AND A HARM-INDUCING STRATEGY

### A. Industrial Livestock Operations Contribute Significant Greenhouse Gas Emissions to the Atmosphere

In addition to local and regional air and water pollution, dairies are a substantial source of California's greenhouse gas emissions. **Livestock methane emissions account for 6.1 percent of statewide GHG emissions.**[18]

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**16** Big Ag, Big Oil and California's Big Water Problem, Food and Water Watch. Available at: https://www.foodandwaterwatch.org/wp-content/uploads/2021/10/CA-Water-White-Paper.pdf.

**17** According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*

**18** California Greenhouse Gas Emissions for 2000-2020, October 26. 2022, Page 9. Available at: https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

Liquid manure-filled lagoons produce a significant amount, although not all, of livestock methane emissions. About half of a typical large dairy's methane emissions come from the cow's digestion processes (called enteric emissions). The industry's intentional decision to store manure in lagoons and subsequently apply wet manure to land is the direct cause of methane and nitrous oxide emissions from manure. Livestock operations remain free from regulation for greenhouse gas emissions despite their significant impact.

### B. Dairy Digesters Do Not Adequately Address Climate and Other Pollutants from Livestock Operations and Perpetuate Dependence on Polluting Fuels

Dairy digesters purport to address methane emissions from massive amounts of liquefied manure stored anaerobically in lagoons. Digesters basically cover the intentionally-created manure pits, capture the various gasses, and deliver the gas to facilities that combust the fuel onsite or scrub out impurities leaving methane gas for off site combustion. Digesters do not do anything to address the roughly equal amount of GHG emissions from enteric fermentation (intestinal gasses) or from the composting and application of digested manure to land. The captured methane gas can be combusted onsite, used as a transportation fuel, combusted as a fuel, converted through steam reformation to produce hydrogen, or upgraded and injected into gas pipelines for transportation fuel, gas in buildings, generating electricity, and other uses. Some dairies have stand-alone digesters and some dairies participate in a factory farm gas cluster. A factory farm gas cluster connects several dairies and dairy digesters with an upgrading facility so that the gas from many dairies can be processed at one site and then injected into the gas pipeline. This "pipeline quality" gas, marketed as clean yet molecularly almost identical to conventional fossil gas, is subsidized by ratepayers and used to justify the continued operation of gas pipelines that otherwise should be phased out.

**Digesters do not do anything to decrease overall air pollution or groundwater pollution from dairies.**

### C. The Relevant Regulatory History Has Exacerbated the Impacts from Industrial Livestock Operations

The Global Warming Solutions Act of 2006 (AB 32 [Nunez]) tasked CARB with developing a plan to reduce GHG emissions generally and in 2013, Senate Bill 605 (Lara) required CARB to develop a plan to reduce emissions of Short-Lived Climate Pollutants, including methane. In 2016, the legislature passed both SB 32 (Pavley) which built upon AB 32's GHG reduction mandates, and SB 1383 (Lara), which focused on methane and other short-lived climate pollutants. SB 1383 set methane emission targets and required CARB to develop and begin implementing a strategy to meet those targets. The bill specifically included a target for methane emission reductions from livestock manure and created both insulation from direct regulation of livestock methane and policies and incentives designed to increase production of factory farm gas. Notably, SB 1383 prohibited direct regulation of methane emissions from livestock manure until 2024 and required CARB to make significant findings of economic feasibility prior to instituting regulations and even further limited the state's authority to regulate enteric emissions.

Furthermore, it required CARB and the CPUC to develop financial mechanisms and incentives to support the production of dairy-produced energy.[19] In so doing, California transitioned from allowing the dairy industry to expand and emit more unabated methane regardless of its impact to rewarding the industry for its polluting practices and incentivizing the creation of even more liquefied manure at ever larger dairies. Protection from regulation coupled with increased subsidies and incentives illustrate the preferential treatment the dairy industry has been granted compared to other polluting sectors.[20]

In 2018, CARB updated the Low Carbon Fuel Standard (LCFS) program to incorporate "avoided methane" into the calculation of carbon intensity scores. The result: factory farm gas became the most carbon negative fuel in the LCFS market, and thus, the most valuable. The LCFS also allows dairies that are already being paid with public funds to reduce methane with dairy digesters to double-dip by claiming the LCFS incentive was the reason for the reductions, blatantly evading the AB 32 prohibition on "non-additional" reductions from being sold into market-based mechanisms.

### D. Factory Farm Gas Production and Deployment is Significantly Subsidized and Therefore Highly Profitable for Large Dairies

The current regulatory landscape provides significant subsidies to dairies to install digesters and produce factory farm gas. This funding includes CDFA's DDRDP, CPUC ratepayer funding, CEC's PIER, EPIC, and Clean Transportation funding, and CARB's Aliso Canyon Mitigation Funding. To date just these direct cash subsidies total close to $700 million with the majority of this funding coming from legislative appropriations to the Dairy Digester and Research Development Program (DDRDP) and utility rate-payers. The Legislature, through annual appropriations from the Greenhouse Gas Reduction Fund and General Fund, has allocated over $200 million to the DDRDP and the CPUC has directed almost $400 million of rate–payer funds to support development and operations of dairy digesters and related infrastructure.

In addition to these direct subsidies along with credit sales available through California's Cap-and-Trade offset program, the Low Carbon Fuel Standard (LCFS) creates a lucrative credit market for industrial dairies that install digesters. CARB designed a life cycle analysis that excludes upstream and downstream greenhouse gas emissions and **treats liquified manure lagoons (and the methane they create) not as an intentionally chosen cost-cutting measure but as a necessary, inevitable part of operating a dairy, which it plainly is not.**

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**19** See "Veto Request – Senate Bill 1383 (Lara) – Dairy Industry Exemptions from short-lived climate pollutants: methane emissions" (September 13, 2016) https://drive.google.com/file/d/1OhQ4bpGX6eNEhgC64Mneel2jpH6Ja5xl/view?usp=sharing

**20** The legislative hearing for Senate Bill 1383 sheds light on the unprecedented benefits the Legislature provided the dairy industry, provoking a lobbyist for the oil industry to warn that it would return to the Legislature for its version of special treatment. See Assembly Natural Resources Committee, Hearing on Senate Bill 1383, available at http://calchannel.granicus.com/MediaPlayer.php?view_id=23&clip_id=4009 (beginning at hour 1:12) (last visited October 24, 2022).

As noted earlier, CARB has determined that methane captured through the production of gas magically makes biomethane carbon negative, and thus generates far more credits for sale in the LCFS credit market than if CARB had treated it like every other fuel. The result has been a deluge of credits which creates a massive windfall for industrial dairies and factory farm gas producers.

The dairy industry is very aware of the monumental investment California made to support the production of factory farm gas and the lucrative LCFS credit market for gas. In fact, the dairy industry itself anticipates a future where "milk has become the by-product of manure production." [21]

Studies project that larger dairies can enjoy a third to a half of their revenue from LCFS credit revenues,[22] begging the question - what's worth more, a cow's milk or its poop?[23] And the necessary follow-up: if we're even asking these questions, what perverse incentives have we created and to what consequences will they lead?

### E. The Resulting Profit Incentive Favors and Entrenches Harmful Practices and Drives Industrial Dairy Expansions

The narrative echoed by the dairy industry and those that profit from buying and selling LCFS credits treats the methane pollution as some kind of inevitable consequence, a natural by-product of dairy production that demands a solution. This narrative entirely ignores the fact that the liquefied manure and the associated massive methane problem was the path that state and local governments and dairy operators themselves chose to follow despite knowing the environmental degradation those decisions would create. And now the state's solution to our methane disaster has itself reinforced harmful manure management and industrial-scale dairy practices that entrench and intensify air and water pollution. Data show that all of these incentives have contributed to an intensification of dairy expansions as dairy operators and those profiting from the LCFS respond to the market demand for manure-based fuels and the lucrative credit markets by expanding dairy operations to produce more manure.

Merced County provides an apt example of the effect this regulatory landscape has on expanding industrial dairy operations. For instance, the Merced Planning Department posts recently prepared environmental documents on the Merced County website.Based solely on the information on this website, Merced County has permitted, or is in the process of permitting, two biogas pipeline and infrastructure projects, ten dairy expansions, and one new 28,000 cow dairy.[24]

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21 See: https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html. Also see: https://twitter.com/drcrystalheath/status/1587320922578378752?s=20&t=sm90vQRFTh91HZ9zY4Yzgg.

22 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

23 Smith, Aaron (2021) "What's Worth More: A Cow's Milk or its Poop?" Ag Data News Blog. (February 2021) Available at https://asmith.ucdavis.edu/news/cow-power-rising.

24 See Environmental Documents, available at https://www.countyofmerced.com/414/Environmental-Documents (last visited December 19, 2022).

The biogas cluster and pipeline projects facilitate dairy expansions to monetize and incentivize increased dairy herds and manure generation. The total additional number of dairy cows (milk cows and support stock) from the above-listed projects is 46,148 cows. It's important to note that several counties do not require environmental review for dairy expansions. In those counties, it is much harder – if not impossible – to assess the extent to which dairies have grown and/or consolidated.

Both the historical expansion of the California Dairy industry and the more recent perverse effects of the LCFS that drive herd expansions show how local land use and Senate Bill 1383 have encouraged both dairy industry expansion and dramatic increases in methane pollution. And instead of requiring the industry to limit its pollution, the Legislature rewarded the reckless expansion by paying operators to profit from the methane emissions they chose to create in the first place. As one study on the impacts of the LCFS notes, "in this instance the largest polluter is the one receiving a large subsidy." [25]

### F. Factory Farm Gas Production Itself Exacerbates Existing Environmental Impacts from Industrial Dairies

Factory farm gas production requires liquified manure lagoons, a profit-maximizing practice that exacerbates water pollution and as discussed throughout this briefing paper, subsidies for factory farm gas incentivize the growth of herds and concentration of animals, which results in increased air and water pollution. Additionally, the very production and use of factory farm gas creates pollution of its own.

Anaerobic digesters increase ammonia emissions, which in turn react with oxides of nitrogen (NOx) to form ammonium nitrate, which significantly contributes to fine particulate matter (PM2.5) pollution.[26] One study found that use of an anaerobic digester increased ammonia emissions from manure as a result of changes in the composition of digested, as compared to undigested, manure. [27]

Combusting factory farm gas on-site, including digester engines powering turbines to generate LCFS credits for electric vehicle fuel, emit significant and unabated additional NOx, PM2.5, and volatile organic compound (VOC) emissions in the air basin. Combined, both effects exacerbate the PM2.5 pollution crisis in the San Joaquin Valley. When upgraded to be used in place of fossil natural gas, it produces all the same emissions when combusted, whether as transportation fuel or used in buildings.

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25 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

26 Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

27 See Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, Ecosystems & Environment (2017).

Moreover, factory farm gas production relies upon methane digesters, which require "abundant water resources, with a ratio equal to 1:1 of the amount of water and manure to be loaded into the digester,"[28] to pump and dilute manure. In arid climates it may be necessary to pump groundwater for this purpose.[29]

### G. Factory Farm Gas Credits Facilitate Ongoing Pollution from Fossil Fuel Production and Combustion

As described above, transportation fuels derived from dairy and swine manure receive LCFS credits and the amount of those credits entering the market has been drastically inflated as a result of improper negative carbon intensity values and non-additional credits. In 2021, these fuels represented approximately 10 percent of all credits sold.[30] Because the LCFS authorizes fuel producers to purchase credits to meet the LCFS market-based compliance mechanism's emission limits, the excessive and illegitimate credits generated by factory farm gas producers allow fossil fuel producers – oil companies – to refine and sell more of their fossil fuels. While communities in the San Joaquin Valley suffer the air, water, and nuisance pollution from factory farm gas fuel production, communities near refineries and near major transportation corridors endure racially disparate impacts from the production and combustion of fossil fuels benefitting from those credits. For example, Black Californians experience twice the PM2.5 burden of white Californians from Cap and Trade facilities, while "Black Californians experience PM2.5 concentrations from refineries that are three times greater than all other stationary source sectors combined that are covered by the Cap-and-Trade Program."[31] Further, "African American, Latino, and Asian Californians are exposed to more PM2.5 pollution from cars, trucks, and buses than white Californians. These groups are exposed to PM2.5 pollution 43, 39, and 21 percent higher, respectively, than white Californians." Additionally, "[T]he lowest-income households in the state live where PM2.5 pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[32]

In other words, as a result of CARB's factory farm gas policies, communities on both sides of the LCFS credit transaction subsidize polluters with compromised health and well-being.

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28 Tatiana Nevzorova & Vladimir Kutcherov, Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review, 26 ENERGY STRATEGY REVIEWS 7 (Oct. 14, 2019), https://www.sciencedirect.com/science/article/pii/S2211467X19301075#bib113.

29 ENVTL. PROTECTION AGENCY, AGSTAR, PROJECT DEVELOPMENT HANDBOOK: A HANDBOOK FOR DEVELOPING ANAEROBIC DIGESTION/BIOGAS SYSTEMS ON FARMS IN THE UNITED STATES 9-5, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

30 See CARB, LCFS Quarterly Data Spreadsheet, available at https://ww2.arb.ca.gov/sites/default/files/2022-10/quarterlysummary_103122_1.xlsx (data available under "Feedstock" tab).

31 *Id.*

32 *Union of Concerned Sci., Inequitable Exposure to Air Pollution from Vehicles in California* (Feb. 2019), https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf.

## V. CHANGING COURSE: CREATING A NEW PATH FORWARD

We have the opportunity and need to reshape the regulatory framework for livestock methane and factory farm gas to effectively reduce greenhouse gas emissions from industrial livestock operations while cutting off profit motives for concentrating livestock and manure which intensify climate impacts, exacerbate environmental degradation, and perpetuate dumping on San Joaquin Valley communities. We lay out three approaches below for rectifying existing deficiencies: correcting inadequacies in the Low Carbon Fuel Standard program, regulating livestock methane emissions, and excluding factory farm gas from inclusion in our clean energy portfolio.

### A. Fix the Low Carbon Fuel Standard Program

The legislature should step in to ensure an updating to the LCFS and other programs to account for full lifecycle emissions, prohibit claiming of non-additional reductions, prevent harm to lower income communities and communities of color, and eliminate windfall profits due to lack of regulation.

Although a number of regulatory actions are responsible for driving these troubling trends in California's dairy industry, the LCFS is currently the most directly responsible for incentivizing herd concentration and polluting manure management practices. CARB is preparing to open a rulemaking to update the LCFS yet,to date there has been no commitment to address the issues raised above. Although CARB staff have not released an official scope for the rulemaking, in a recent workshop CARB proposed continuing to issue the massively inflated credits until at least 2040.[33] Additionally, CARB has indicated that they will rely on the LCFS to ensure the ongoing profitability and viability of biomethane to facilitate its transition into industrial energy markets when its purported use as transportation fuels gives way to our electric vehicle future.

Given the urgency of the issue and CARB's demonstrated unwillingness to address the consequences of its failing regulatory approach, the Legislature is well-positioned to provide much-needed direction to CARB to ensure the program is in line with California's commitments to addressing GHG emissions and environmental injustice.

### B. Eliminate Factory Farm Gas from Definitions of Renewable Energy

As brought to the forefront during hearings on SB 1020 last year, resources eligible to meet the requirements of the Renewable Portfolio Standard (RPS) and SB 100 (RPS plus zero carbon resources) include "digester gas" which includes factory farm gas.

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33 See presentation for CARB Low Carbon Fuel Standard Workshop November 9, 2022. Available at https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf.

The definition of factory farm gas as “renewable” supports its inclusion in existing climate programs, such as the LCFS[34] and emerging energy technologies, such as hydrogen[35] and opens up or expands markets and subsidies for the dirty fuel. By eliminating factory farm gas from the definition of renewable energy, California can ensure current and future efforts to transition California’s energy and transportation systems are real environmental justice solutions and not a polluting cash cow. Cleaning up our energy sector is challenging enough already without false solutions muddying the water.

## C. Regulate Livestock Greenhouse Gas Emissions

As stated above, SB 1383 permits CARB to directly regulate livestock methane emissions starting in 2024 but provides CARB discretion and several off-ramps that provide ready justifications for CARB to continue the failing LCFS-centered strategy, including using the LCFS to subsidize factory farm gas for to support its growth in industrial sectors. The Legislature must direct CARB to adopt mandatory regulations and acknowledge the last-minute dairy methane provisions in Senate Bill 1383 were an unprecedented and ill-advised industry giveaway. California must treat the dairy industry like every other major source of greenhouse gas emissions. We cannot continue to treat the most climate-impacting practices as inevitable and force the public to pay polluters to stop polluting thereby rewarding the biggest and worst polluters.

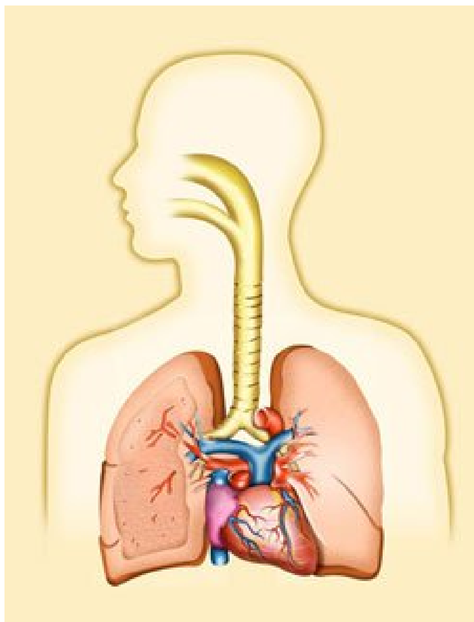
**For more information contact: Jamie Katz, Staff Attorney, jbkatz@leadershipcounsel.org**

**34** Cal. Code Regs. Tit 17 § 95481-95482.
**35** Pub. Res. Code § 25664

# ATTACHMENT F

# Health Effects of Ozone Pollution

Ozone in the air we breathe can harm our health, especially on hot sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects.



Ozone is a powerful oxidant that can irritate the airways.

### For Healthcare Providers

Ozone and Your Patients' Health: Training for Healthcare Providers <https://epa.gov/ozone-pollution-and-your-patients-health>

## Who is at risk?

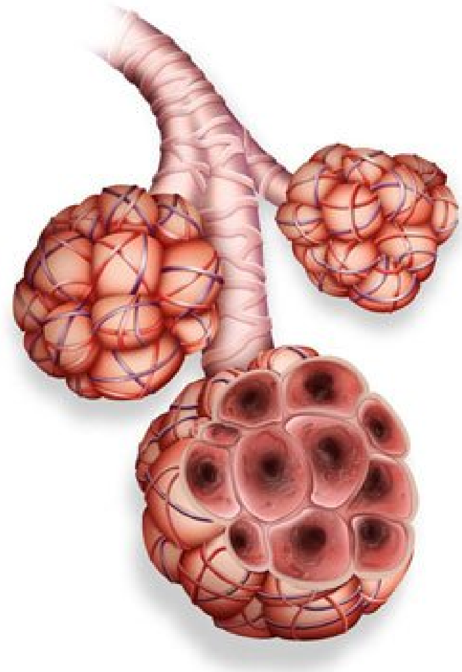
People most at risk from breathing air containing ozone include people with asthma, children, older adults, and people who are active outdoors, especially outdoor workers. In addition, people with certain genetic characteristics, and people with reduced intake of certain nutrients, such as vitamins C and E, are at greater risk from ozone exposure.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

## What health problems can ozone cause?

Depending on the level of exposure, ozone can:

- Cause coughing and sore or scratchy throat.
- Make it more difficult to breathe deeply and vigorously and cause pain when taking a deep breath.
- Inflame and damage the airways.
- Make the lungs more susceptible to infection.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.



Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath.

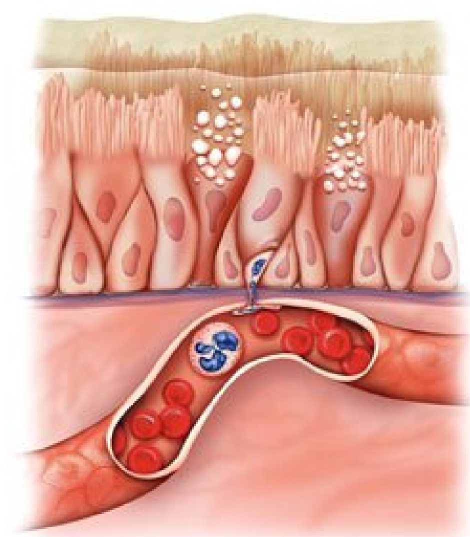
Some of these effects have been found even in healthy people, but effects can be more serious in people with lung diseases such as asthma. They may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions.

Long-term exposure to ozone is linked to aggravation of asthma, and is likely to be one of many causes of asthma development. Studies in locations with elevated concentrations also report associations of ozone with deaths from respiratory causes.

# How can I reduce these health risks?

The AirNow Web site <http://www.airnow.gov/> provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is.

EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info <http://www.enviroflash.info/>.



With inflammation, the airway lining is damaged. It has been compared to the skin inflammation caused by sunburn.

# Pamphlets and other resources:

- Printable pamphlets and booklets about ozone effects on air quality and health. <https://epa.gov/ground-level-ozone-pollution/pamphlets-about-ozone-effects-air-quality-and-health>

- EPA's Air Quality Guide for Ozone <https://epa.gov/sites/production/files/2017-12/documents/air-quality-guide_ozone_2015.pdf> provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health: Training for Health Care Providers <https://epa.gov/ozone-pollution-and-your-patients-health> is designed for family practice doctors, pediatricians, nurse practitioners, asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.
- AirNow Health Providers Information <https://www.airnow.gov/air-quality-and-health/your-health/> provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site <https://epa.gov/asthma> provides information for EPA's Communities in Action Asthma Initiative that includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.

Contact Us <https://epa.gov/ground-level-ozone-pollution/forms/contact-us-about-ozone-pollution> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON MAY 24, 2023

**Privacy and Security Notice**

<https://epa.gov/privacy/privacy-and-security-notice>

# ATTACHMENT G

**ENVIRONMENTAL PROTECTION AGENCY**

**40 CFR Part 52**

**[EPA–R09–OAR–2021–0884; FRL–9292–03–R9]**

# Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California

**AGENCY:** Environmental Protection Agency (EPA).

**ACTION:** Proposed rule.

**SUMMARY:** On December 29, 2021, the Environmental Protection Agency (EPA or ''Agency'') published a proposed rule to approve the State of California's Serious area plan for the San Joaquin Valley (SJV) for the 2012 annual fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) for all Serious $PM_{2.5}$ area planning requirements, except for contingency measures, which the EPA proposed to disapprove. Based on adverse comments submitted on that proposed rule and as a result of a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking for the 2006 24-hour $PM_{2.5}$ NAAQS, the EPA has reconsidered its prior proposal and now proposes to disapprove the State's plan for certain Serious area planning requirements for the 2012 annual $PM_{2.5}$ NAAQS. The nonattainment plan elements that the EPA proposes to disapprove include the plan's best available control measures (BACM) demonstration for ammonia and building heating, demonstrations of attainment and reasonable further progress, quantitative milestones, and motor vehicle emission budgets. The EPA is also proposing to disapprove the State's optional precursor demonstration for ammonia. We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged. The EPA will accept comments on this new proposed rule during a 45-day public comment period and public hearing, as described in this notice.

**DATES:** Any comments must arrive by November 21, 2022.

*Public hearings:* The EPA will host two public hearings on this proposed rule. The first will take place November 2, 2022, 7:30 p.m. to 8:30 p.m. The second will take place November 3, 2022, 7:00 p.m. to 8:00 p.m. The hearings will be held to accept oral comments on this proposed rule. Immediately prior to each public hearing, and on October 28, 2022, the EPA will host public meetings on this proposed rule. For further information on the public hearings and public meetings, please see the **ADDRESSES** and **SUPPLEMENTAL INFORMATION** sections.

**ADDRESSES:** The November 2, 2022 public hearing will take place at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The November 3, 2022 public hearing will take place at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305.

Submit your comments, identified by Docket ID No. EPA–R09–OAR–2021–0884, at *https://www.regulations.gov.* For comments submitted at *Regulations.gov*, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

**FOR FURTHER INFORMATION CONTACT:** For questions regarding this proposed rule, please contact Rory Mays, Air Planning Office (AIR–2), EPA Region IX, (415) 972–3227. For questions regarding the public hearings and related public meetings, please contact Kelley Xuereb, Immediate Office (AIR–1), EPA Region IX, (415) 947–4171. Both can be reached by emailing *SJVPublicMeetings@epa.gov.*

**SUPPLEMENTARY INFORMATION:** In addition to the two in-person public hearings, the EPA will host three public meetings. The public meetings are an informal opportunity to speak with EPA staff about the action. We will not accept public comments during the public meetings. The first meeting will be held virtually on October 28, 2022, 12:00 p.m. to 2:00 p.m. Participants can register to attend the meeting at: *https://usepa.zoomgov.com/meeting/register/vJItc-qppzooGCZI10LqoTXf6OpNZIVbWco.*

The second will take place on November 2, 2022, 5:30 p.m. to 7:00 p.m. prior to the public hearing at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The third will take place on November 3, 2022, 5:00 p.m. to 6:30 p.m. prior to the public hearing at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305. Spanish translation will be available during all three events. If you would like to submit a request for reasonable accommodation, please email *SJVPublicMeetings@epa.gov.* For additional information and updates, please visit: *https://www.epa.gov/sanjoaquinvalley.*

Throughout this document, ''we,'' ''us,'' and ''our'' refer to the EPA.

## Table of Contents



## I. Background for Proposed Action

The EPA discussed background, applicable State implementation plan (SIP) submissions, completeness review, and Clean Air Act (CAA or ''Act'') requirements for the SJV Serious $PM_{2.5}$

nonattainment area [1] in sections I, II, and III of our December 29, 2021 proposed rule on California's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.[2] We refer to that proposed rule herein as the ''2021 Proposed Rule,'' briefly summarize the relevant CAA requirements and our previous proposed action with respect to those requirements here, and rely on the more detailed expositions in that proposed rule.

The EPA promulgated the primary annual $PM_{2.5}$ NAAQS of 12.0 micrograms per cubic meter (μg/m³) in 2012 (''2012 annual $PM_{2.5}$ NAAQS''),[3] designated and classified the SJV as Moderate nonattainment for this NAAQS in 2015,[4] and reclassified the SJV from Moderate to Serious nonattainment for this NAAQS in our final rule published November 26, 2021.[5] That reclassification action required California to submit a ''Serious area'' attainment plan. Such an attainment plan must include, among other things, provisions to assure that, under CAA section 189(b)(1)(B), the BACM for the control of direct $PM_{2.5}$ and $PM_{2.5}$ precursors are implemented no later than four years after reclassification of the area and a demonstration (including air quality modeling) that the plan provides for attainment of this NAAQS as expeditiously as practicable but no later than December 31, 2025. That reclassification action also triggered statutory deadlines for California to submit SIP submissions addressing the Serious area attainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS: June 27, 2023, for emissions inventories, BACM, and nonattainment new source review (NSR), and December 31, 2023, for the attainment demonstration and related planning requirements.

### *A. Applicable SIP Submissions, Completeness Review, and Clean Air Act Requirements*

In this proposed rule, the EPA is proposing action on portions of two SIP submissions submitted by the California Air Resources Board (CARB) to address combined nonattainment plan requirements for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS in the SJV.[6] Specifically, the EPA is proposing to act only on those portions of the following two plan submissions that pertain to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS: (1) the ''2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' adopted by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD or District) on November 15, 2018, and by CARB on January 24, 2019 (''2018 $PM_{2.5}$ Plan''); [7] and (2) the ''San Joaquin Valley Supplement to the 2016 State Strategy for the State Implementation Plan,'' adopted by CARB on October 25, 2018 (''Valley State SIP Strategy'').

We refer to the relevant portions of these SIP submissions collectively in this proposal as the ''SJV $PM_{2.5}$ Plan'' or ''Plan.'' The SJV $PM_{2.5}$ Plan addresses attainment plan requirements for multiple $PM_{2.5}$ NAAQS in the SJV. CARB submitted the SJV $PM_{2.5}$ Plan to the EPA as a revision to the California SIP on May 10, 2019.[8] These SIP submissions became complete by operation of law on November 10, 2019.[9] In the 2021 Proposed Rule, we proposed to find that the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy each met the procedural requirements for public notice and hearing in CAA sections 110(a)(1) and (2) and 110(l) and 40 CFR 51.102.

In our 2021 Proposed Rule, we also summarized the CAA requirements applicable to Serious $PM_{2.5}$ nonattainment areas.[10] In the current proposed rule, we are proposing action with respect to the following requirements:

(1) Provisions to assure that BACM, including best available control technology (BACT), for the control of direct $PM_{2.5}$ and all $PM_{2.5}$ precursors shall be implemented no later than four years after the area is reclassified (CAA section 189(b)(1)(B)), unless the State elects to make an optional precursor demonstration that the EPA approves authorizing the State not to regulate one or more of these pollutants;

(2) A demonstration (including air quality modeling) that the plan provides for attainment as expeditiously as practicable but no later than the end of the tenth calendar year after designation as a nonattainment area (*i.e.,* December 31, 2025, for the SJV for the 2012 annual $PM_{2.5}$ NAAQS) (CAA sections 188(c)(2) and 189(b)(1)(A)(i));

(3) Plan provisions that require reasonable further progress (RFP) (CAA section 172(c)(2));

(4) Quantitative milestones that the State must meet every three years until the EPA redesignates the area to attainment and which demonstrate RFP toward attainment by the applicable date (CAA section 189(c)); and

(5) Motor vehicle emissions budgets (budgets) for 2025 (CAA section 176(c)).

We are also proposing to disapprove the State's optional precursor demonstration for ammonia.[11]

In addition, the State's Serious area plan must meet the general requirements applicable to all SIP submissions under section 110 of the CAA, including the requirement to provide necessary assurances that the implementing agencies have adequate personnel, funding, and authority under section 110(a)(2)(E); and the requirements concerning enforcement provisions in section 110(a)(2)(C).

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[1] For a precise description of the geographic boundaries of the SJV $PM_{2.5}$ nonattainment area, see 40 CFR 81.305.

[2] 86 FR 74310 (December 29, 2021).

[3] 78 FR 3086 (January 15, 2013) and 40 CFR 50.18. Unless otherwise noted, all references to the $PM_{2.5}$ standards in this notice, including all instances of ''2012 annual $PM_{2.5}$ NAAQS,'' are to the 2012 primary annual NAAQS of 12.0 μg/m³ codified at 40 CFR 50.18.

[4] 80 FR 2206 (January 15, 2015) (codified at 40 CFR 81.305).

[5] 86 FR 67343 (November 26, 2021).

[6] In our 2021 Proposed Rule, we also proposed action on a third SIP submission dated July 19, 2019. 86 FR 74310, 74311. However, the relevant component of that submission pertained only to contingency measures, and we are not modifying our proposed action on contingency measures in this proposed rule.

[7] The 2018 $PM_{2.5}$ Plan was developed jointly by CARB and the District.

[8] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX. Previously, in separate rulemakings, the EPA has finalized action on the portions of the SJV $PM_{2.5}$ Plan that pertain to the 1997 annual $PM_{2.5}$ NAAQS, the 1997 24-hour $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS. See 86 FR 67329 (November 26, 2021) (final rule regarding the 1997 annual $PM_{2.5}$ NAAQS); 87 FR 4503 (January 28, 2022) (final rule regarding the 1997 24-hour $PM_{2.5}$ NAAQS); 85 FR 44192 (July 22, 2020) (final rule regarding the 2006 24-hour $PM_{2.5}$ NAAQS, except contingency measures); and 86 FR 67343 (November 26, 2021) (final rule regarding the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS and contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[9] 87 FR 74310, 74311–74312. We note that, with respect to plans previously required for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS, including the Moderate area plan only for the 2012 annual $PM_{2.5}$ NAAQS, the EPA had made findings of failure to submit effective January 7, 2019, that triggered sanctions clocks. 83 FR 62720 (December 6, 2018). Following the May 10, 2019 submission of the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy, the EPA affirmatively determined that the SIP submissions addressed the deficiency that was the basis for such findings, resulting in the termination of the associated sanctions clocks. Letter dated June 24, 2020, from Elizabeth Adams, Director, Air and Radiation Division, EPA Region IX, to Richard W. Corey, Executive Officer, CARB. However, the findings of failure to submit did not apply to the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS because it was not yet required, and the June 24, 2020 completeness letter did not address the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

[10] 87 FR 74310, 74313.

[11] We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged.

The EPA provided its preliminary views on the CAA's requirements for particulate matter plans under part D, title I of the Act in the following guidance documents: (1) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble''); [12] (2) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental'' (''General Preamble Supplement''); [13] and (3) ''State Implementation Plans for Serious PM–10 Nonattainment Areas, and Attainment Date Waivers for PM–10 Nonattainment Areas Generally; Addendum to the General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble Addendum'').[14] More recently, in an August 24, 2016 final rule entitled, ''Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements'' (''$PM_{2.5}$ SIP Requirements Rule''), the EPA established regulatory requirements and provided further interpretive guidance on the statutory SIP requirements that apply to areas designated nonattainment for all $PM_{2.5}$ NAAQS.[15] We discuss these regulatory requirements and interpretations of the Act as appropriate in our evaluation of the State's submissions below.

*B. December 29, 2021 Proposed Rule*

In our 2021 Proposed Rule, the EPA proposed to approve the SJV $PM_{2.5}$ Plan's: (1) emissions inventory for the 2013 base year; (2) precursor demonstrations that emissions of ammonia, sulfur oxides ($SO_X$), and volatile organic compounds (VOC) do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV; (3) BACM demonstration for emission sources of direct $PM_{2.5}$ and nitrogen oxides ($NO_X$); (4) attainment demonstration based on air quality modeling [16] and emissions reductions related to aggregate commitments; (5) RFP demonstration; (6) quantitative milestones; and (7) motor vehicle emission budgets. We briefly summarize several aspects of those proposed approvals in the applicable sub-sections of section II of this proposed rule.

We also proposed to disapprove the Plan's contingency measures and noted the requirements for nonattainment NSR and the State's separate submission for the nonattainment NSR requirements. However, as we are not re-proposing any action on contingency measures nor nonattainment NSR in this proposed rule, we do not summarize those proposals herein.[17] In addition, we are not re-proposing any action on the Plan's precursor demonstrations for $SO_X$ and VOC in this proposed rule; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's demonstrations that emissions of $SO_X$ and VOC do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV remains unchanged.

Finally, we are not re-proposing any action in this proposed rule on the Plan's base year emissions inventory; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's base year emissions inventory remains unchanged. Nevertheless, we briefly summarize our prior proposal [18] given the role that base year emissions inventories play in developing a plan's control strategy and attainment and RFP demonstrations.

The 2018 $PM_{2.5}$ Plan includes summaries of the planning emissions inventories for direct $PM_{2.5}$ and all $PM_{2.5}$ precursors ($NO_X$, $SO_X$,[19] VOC,[20] and ammonia) and related documentation. The Plan contains annual average daily emission inventories for 2013 through 2028 projected from the 2012 actual emissions inventory,[21] including the 2013 base year, the 2019 and 2022 RFP milestone years, the 2025 Serious area attainment year, and a 2028 post-attainment RFP year. The EPA proposed to approve the 2013 base year emissions inventory in the 2018 $PM_{2.5}$ Plan as meeting the requirements of CAA section 172(c)(3) and 40 CFR 51.1008. We also proposed to find that the future year baseline inventories in the 2018 $PM_{2.5}$ Plan satisfy the requirements of 40 CFR 51.1008(b)(2) and 51.1012(a)(2) and provide an adequate basis for the control measure, attainment, and RFP demonstrations for the 2012 annual $PM_{2.5}$ NAAQS in the 2018 $PM_{2.5}$ Plan.

*C. Adverse Comments Submitted January 28, 2022*

The EPA received adverse comments on our 2021 Proposed Rule from a coalition of 13 environmental, public health, and community organizations (collectively referred to herein as ''Public Justice'').[22] We are not responding to these comments (in the sense of a final rulemaking action) in this proposed rule, but the Agency has taken them into account with respect to the Serious area plan elements discussed in this proposed rule.

Overall, the commenters argue that the EPA must disapprove the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan based on alleged nonattainment plan requirement deficiencies in the submissions. We introduce these comments in this section of this proposed rule and present more detailed summaries and discussion of the comments in sections II.A (ammonia precursor demonstration), II.B.2 (BACM for ammonia emission sources), II.B.3 (BACM for building heating emission sources), II.C (attainment demonstration), and IV (Title VI of the Civil Rights Act).

Regarding CAA requirements for $PM_{2.5}$, Public Justice points to a history of failures to timely attain the 1997 annual $PM_{2.5}$ NAAQS in the SJV and states that ''[r]egulators point to a host of excuses from weather, to international sources, to Federal inaction, but repeatedly the State and Air District have refused to adopt feasible controls or regulate politically powerful entities'' such as agricultural sources of air pollution.[23] The commenters take issue with the EPA's proposal to approve the plan for the stricter 2012 standard ''without performing its duty to hold [CARB] and the [District] accountable to meet the

[12] 57 FR 13498 (April 16, 1992).

[13] 57 FR 18070 (April 28, 1992).

[14] 59 FR 41998 (August 16, 1994).

[15] 81 FR 58010 (August 24, 2016).

[16] We described 2018 $PM_{2.5}$ Plan's air quality modeling and our evaluation thereof in section IV.C of the 2021 Proposed Rule.

[17] Regarding nonattainment NSR, please see the EPA's separate rulemaking on the State's November 20, 2019 SIP submission of amendments to SJVUAPCD Rule 2201 (''New and Modified Stationary Source Review''). 87 FR 45730 (July 29, 2022) (proposed limited approval and limited disapproval of the Rule 2201 amendments).

[18] See section IV.A of the EPA's 2021 Proposed Rule.

[19] The SJV $PM_{2.5}$ Plan generally uses ''sulfur oxides'' or ''$SO_X$'' in reference to $SO_2$ as a precursor to the formation of $PM_{2.5}$. We use $SO_X$ and $SO_2$ interchangeably throughout this notice.

[20] The SJV $PM_{2.5}$ Plan generally uses ''reactive organic gasses'' or ''ROG'' in reference to VOC as a precursor to the formation of $PM_{2.5}$. We use ROG and VOC interchangeably throughout this notice.

[21] 2018 $PM_{2.5}$ Plan, App. B, B–18.

[22] Comment letter dated and received January 28, 2022, from Brent Newell, Public Justice, et al., to Rory Mays, EPA, including Exhibits 1 through 47. We note, however, that there is no Exhibit 23; so, there are 46 exhibits in total. Email dated February 1, 2022, from Brent Newell, Public Justice, to Rory Mays, EPA Region IX. The 13 environmental, public health, and community organizations are Public Justice, Central Valley Environmental Justice Network, Association of Irritated Residents, Central Valley Air Quality Coalition, Leadership Counsel for Justice and Accountability, Valley Improvement Projects, The LEAP Institute, Little Manila Rising, Center for Race, Poverty, and the Environment, Central California Asthma Collaborative, Animal Legal Defense Fund, National Parks Conservation Association, and Food and Water Watch (collectively ''Public Justice'').

[23] Public Justice Comment Letter, 2.

minimum requirements Congress imposed to protect human health.'' [24] The commenters assert that the EPA relies on flawed, outdated information, ignores feasible controls, refuses to require regulation of ammonia, accepts aggregate commitments in lieu of other control strategies, and fails to address pollution sources in disadvantaged communities in the SJV.[25] With respect to specific CAA requirements, the commenters argue that the EPA must disapprove the Plan's emissions inventory, ammonia precursor demonstration, BACM demonstration, and aggregate commitments.

Regarding Title VI of the Civil Rights Act, the commenters argue that California must provide necessary assurances that the SIP complies with Title VI of the Civil Rights Act, pursuant to CAA section 110(a)(2)(E), and failed to do so.[26] The commenters state that ''$PM_{2.5}$ pollution has a disparate impact on the basis of race in the San Joaquin Valley'' and assert that the Plan fails to meet CAA requirements and ''deliberately ignores obvious sources and control options and inflicts disparate impacts on Black, Latino, Indigenous, and people of color'' in the SJV. Therefore, the commenters advocate that the EPA must disapprove the 2012 annual $PM_{2.5}$ portion of the SJV $PM_{2.5}$ Plan.[27] We address the commenters' Title VI comments in section IV of this proposed rule.

The EPA is now proposing to disapprove the Plan with respect to certain CAA requirements (BACM/BACT for ammonia emission sources, BACM/BACT for building heating emission sources, aggregate commitments, attainment demonstration, RFP demonstration, quantitative milestones, and motor vehicle emission budgets). However, we are not in this proposal comprehensively addressing all issues raised in the Public Justice comment letter.[28]

*D. Ninth Circuit Decision on Related SJV $PM_{2.5}$ Plan*

In a final rule published July 22, 2020, the EPA finalized approval of the portions of the SJV $PM_{2.5}$ Plan [29] that addressed the 2006 24-hour $PM_{2.5}$ NAAQS (except for contingency measures, which the EPA acted on in a subsequent action).[30] On September 17, 2020, a group of five environmental, public health, and community groups (collectively referred to herein as ''Medical Advocates'') petitioned the Ninth Circuit Court of Appeals (''Ninth Circuit'' or ''Court'') for review of the EPA's July 22, 2020 final rule.[31] On April 13, 2022, the Ninth Circuit issued a Memorandum opinion that granted in part and denied in part the petition (''Memorandum Opinion'').[32]

The Ninth Circuit denied the petitioners' challenge with respect to the EPA's approval of enforceable commitments in general and the EPA's approval of the Plan's demonstration of BACM, BACT, and most stringent measures (MSM) for emission sources of direct $PM_{2.5}$ and $NO_X$ for purposes of the 2006 24-hour $PM_{2.5}$ NAAQS.

Significantly, however, the Ninth Circuit also denied in part and granted in part the petitioners' challenge with respect to the EPA's approval of the specific enforceable commitments employed as part of the SJV $PM_{2.5}$ Plan's control strategy to attain the 2006 24-hour $PM_{2.5}$ NAAQS in the SJV by December 31, 2024. The EPA evaluates enforceable commitments based on three factors: (1) the commitment represents a limited portion of the required emission reductions, (2) the State is capable of fulfilling its commitment, and (3) the commitment is for a reasonable and appropriate timeframe. The Ninth Circuit denied the petitioners' challenge with respect to the first and third factors but granted the petitioners' challenge with respect to the second factor.

The Ninth Circuit found that the EPA had misapplied the second factor concerning the State's ability to fulfill the aggregate commitments. The Court reasoned that EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total $NO_X$ reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [33] The Court also rejected the EPA's arguments that: (1) the funding shortfall may be smaller than projected, (2) emission reductions may be less expensive than the strategy predicts, (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls, and (4) California and the District may identify other measures to fulfill their commitments. Instead, the Court decided that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [34] The Court concluded that the EPA's analysis with respect to the second factor for evaluating enforceable commitments was arbitrary and capricious, vacated the final rule with respect to this factor, and remanded the matter to the EPA for further consideration of the second factor.[35]

The EPA is currently considering how to address the Court's vacatur and remand with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan and is not proposing any action with respect to those standards in this proposed rule. However, the Ninth Circuit's decision is very relevant to this proposed rule because the State relied on a common control strategy, including the same enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for purposes of both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan. The EPA acknowledges the deficiency in the factual support for the aggregate commitments identified by the Ninth Circuit and that this remains the case. If the EPA cannot approve the aggregate commitments, then this has a direct bearing on other elements of the State's Serious area SIP submissions for the 2012 annual $PM_{2.5}$ NAAQS. As discussed in section II.C of this proposed rule, based on our reconsideration of the facts concerning the enforceable commitments in the SJV $PM_{2.5}$ Plan with respect to the 2012 annual $PM_{2.5}$ NAAQS in light of the Ninth Circuit's decision, the EPA now proposes to disapprove the State's enforceable commitments and attainment demonstration.

[24] Id.

[25] Id. at 3.

[26] Id. at 10–14.

[27] Id. at 1 and 21.

[28] Additional source categories named by Public Justice include, for example, residential wood burning, open burning, conservation management practices at farming operations, soil $NO_X$ emissions, stationary agricultural internal combustion engines, and cleaner mobile agricultural equipment engines. Public Justice Comment Letter, 18–20.

[29] 85 FR 44192.

[30] 86 FR 67343 (disapproving contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[31] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #1 (9th Cir., September 17, 2020). The five environmental, public health, and community organizations, in order of appearance in the petition, are Medical Advocates for Healthy Air, National Parks Conservation Association, Association of Irritated Residents, and Sierra Club (collectively ''Medical Advocates'').

[32] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022).

[33] Id. at 6.

[34] Id. at 7.

[35] Id. at 10.

## II. Reconsideration of the San Joaquin Valley Serious $PM_{2.5}$ Plan

The EPA has reconsidered its 2021 Proposed Rule, based on adverse comments on that prior proposal and based on a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking. After careful consideration of the issues raised by commenters and the court, the EPA now proposes to disapprove the State's plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV for certain Serious area planning requirements, including: (1) the Plan's precursor demonstration for ammonia; (2) BACM for ammonia emission sources and BACM for building heating emission sources; (3) the modeled attainment demonstration; (4) the RFP demonstration; (5) quantitative milestones; and (6) motor vehicle emission budgets.

In sections II.A through II.C of this proposed rule, pertaining to the Plan's precursor demonstration for ammonia as a $PM_{2.5}$ precursor; BACM/BACT analysis, and modeled attainment demonstration (including reliance on enforceable commitments), we present a brief summary of the 2021 Proposed Rule, a summary of the adverse comments and Ninth Circuit order, as appropriate, and our reconsidered proposal. In sections II.D and II.E, pertaining to the Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets, we present a brief summary of the 2021 Proposed Rule and our reconsidered proposal.[36] We also note that sections II.A (ammonia precursor demonstration) and II.B.1 (BACM for ammonia emission sources) are inter-related in that potential control measures for ammonia emission sources play a role in both: (1) selecting a reasonable percent emission reduction to evaluate modeled ambient $PM_{2.5}$ responses to ammonia emission reductions; and (2) assessing the availability and application of BACM to such sources in the SJV.

### *A. Ammonia Precursor Demonstration*

#### 1. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA described the requirements for $PM_{2.5}$ precursor pollutants, summarized the State's submissions in the SJV $PM_{2.5}$ Plan, and presented our evaluation thereof.[37] We briefly summarize those here with respect to the Plan's demonstration for ammonia as a precursor to $PM_{2.5}$ for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For a comprehensive discussion of Federal requirements for $PM_{2.5}$ precursors and a summary of California's submission, please refer to the following headings in Section IV.B of the 2021 Proposed Rule: (1) Requirements for Control of $PM_{2.5}$ Precursors; and (2) Summary of State's Submission.

Regarding CAA requirements applicable to $PM_{2.5}$ precursors, we explained that the attainment plan requirements of Title I, subpart 4 apply to emissions of direct $PM_{2.5}$ and emissions of $NO_X$, ammonia, $SO_2$, and VOC as $PM_{2.5}$ precursors from all types of stationary, area, and mobile sources, except as otherwise provided in the Act. We further described how the EPA interprets section 189(e) concerning regulation of precursors from major stationary sources to authorize it to determine, under appropriate circumstances, that regulation of specific $PM_{2.5}$ precursors from other sources in a given nonattainment area is not necessary.

As explained in the $PM_{2.5}$ SIP Requirements Rule, a State may elect to submit to the EPA a "comprehensive precursor demonstration" for a specific nonattainment area to show that emissions of a particular precursor from existing sources located in the nonattainment area do not contribute significantly to $PM_{2.5}$ levels that exceed the standard in the area.[38] The contribution analysis may consider the sensitivity of $PM_{2.5}$ to decreases in emissions of the precursor, in addition to the contribution to ambient concentrations of $PM_{2.5}$.[39] If the EPA determines that the contribution of the precursor to $PM_{2.5}$ levels in the area is not significant and approves the demonstration, then the State is not required to control emissions of the relevant precursor in the attainment plan.[40]

The EPA issued the "$PM_{2.5}$ Precursor Demonstration Guidance" ("$PM_{2.5}$ Precursor Guidance"),[41] to provide recommendations to states for analyzing nonattainment area $PM_{2.5}$ and $PM_{2.5}$ precursor emissions and developing such optional precursor demonstrations, consistent with the $PM_{2.5}$ SIP Requirements Rule. The guidance also describes how the State may use a sensitivity-based test, in which the modeled sensitivity or response of ambient $PM_{2.5}$ concentrations to changes in emissions of the precursor is estimated and then compared to a contribution threshold. In addition to comparing the concentration or modeled response to the threshold, the State can consider other information in assessing whether the precursor significantly contributes. The EPA's recommended annual average contribution threshold for the 2012 annual $PM_{2.5}$ NAAQS is 0.2 $\mu g/m^3$.[42] In other words, if the estimated contribution of a precursor at monitors is below this threshold, the EPA considers this evidence that the precursor does not contribute significantly to levels above the $PM_{2.5}$ NAAQS in the area in question; above this threshold, the EPA considers this evidence that the precursor does contribute significantly. The EPA considers this evidence in conjunction with additional information that the State may provide, and determines whether or not the precursor contributes significantly, and so whether the State must evaluate and implement controls of the precursor emissions to the appropriate level (*e.g.,* BACM).

The State presents its precursor demonstration primarily in Appendix G of the 2018 $PM_{2.5}$ Plan, with additional clarifying information in a series of emails available in the docket for this proposed rule. The State estimates that anthropogenic emissions of $NO_X$, ammonia, $SO_X$, and VOC will decrease by 64 percent (%), 1%, 6%, and 9%, respectively, between 2013 and 2025 based on its projected emissions accounting for existing and additional control measures in the Serious area plan.[43] Through a concentration-based analysis, CARB found that ammonium nitrate constituted 5.2 $\mu g/m^3$ of the annual average $PM_{2.5}$ concentrations measured at the Bakersfield California Avenue monitor in 2015, exceeding the recommended threshold,[44] and proceeded to conduct a sensitivity-based analysis.

For analytical purposes in accordance with the EPA's guidance, the State then modeled the sensitivity of ambient $PM_{2.5}$ to hypothetical 30% and 70% reductions in anthropogenic emissions of ammonia in SJV for modeled years

[36] The Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets were not the direct subject of adverse comments nor the Ninth Circuit decision. However, they are based on the Plan's control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS and, thus, the flaws in the Plan's control strategy affect these additional required elements.

[37] 86 FR 74310, 74317–74321.

[38] 40 CFR 51.1006(a)(1).

[39] 40 CFR 51.1006(a)(1)(ii).

[40] 40 CFR 51.1006(a)(1)(iii).

[41] "$PM_{2.5}$ Precursor Demonstration Guidance," EPA–454/R–19–004, May 2019, including Memo dated May 30, 2019, from Scott Mathias, Acting Director, Air Quality Policy Division and Richard Wayland, Director, Air Quality Assessment Division, Office of Air Quality Planning and Standards (OAQPS), EPA to Regional Air Division Directors, Regions 1–10, EPA.

[42] $PM_{2.5}$ Precursor Guidance, 17.

[43] 2018 $PM_{2.5}$ Plan, Ch. 7, 7–5 and Table 7–2.

[44] 2018 $PM_{2.5}$ Plan, App. G, 3.

2013, 2020, and 2024. The results for 2024 are a proxy for the Plan's modeled attainment year of 2025 for the 2012 annual $PM_{2.5}$ NAAQS. For the 30% reduction results for 2024, upon which the State primarily relied, 2 out of 15 monitoring sites in SJV (Madera and Hanford) had modeled responses to ammonia reductions that were above the threshold. The ambient $PM_{2.5}$ response declines substantially from 2020 to 2024, with the decline being generally larger for the sites with the highest projected $PM_{2.5}$ levels. The State supplements the sensitivity analysis for ammonia with consideration of additional information such as emission trends, the appropriateness of future year versus base year sensitivity, available emission controls, and the severity of nonattainment.[45]

The State's precursor demonstration for ammonia also presents a review of District agricultural rules that control VOC emissions, but also provide ammonia reduction co-benefits. The State concludes that a 30% reduction is a reasonable upper bound on the potential ammonia reductions to model. Finally, the State's precursor demonstration presents extensive support for the State's conclusion that there is an ambient excess of ammonia relative to nitrate, *i.e.,* that particulate ammonium nitrate formation in SJV is $NO_X$-limited, and will become increasingly $NO_X$-limited as $NO_X$ reductions increase into the future from the State's motor vehicle control program and other measures the State intends to undertake in the Serious area plan. Based on the forgoing considerations, the State concludes that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

The EPA presented its initial evaluation of the State's ammonia precursor demonstration in section IV.B.3.a of the 2021 Proposed Rule, with more detailed summaries and evaluation in two EPA technical support documents (TSDs): ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's $PM_{2.5}$ Precursor TSD''), and ''Technical Support Document, EPA Evaluation of Ammonia Precursor Demonstration, San Joaquin Valley Moderate Area $PM_{2.5}$ Plan for the 2012 $PM_{2.5}$ NAAQS,'' August 2021 (''EPA's Ammonia Precursor TSD'').

We noted that the EPA's $PM_{2.5}$ Precursor Guidance provides for consideration of future year sensitivity and that consideration of additional information beyond the concentration-based and sensitivity-based analyses may be appropriate in assessing a precursor's significance. We summarized the State's assertions that 30% is a reasonable upper bound for potential ammonia emission reductions based on research cited in Appendix C of the 2018 $PM_{2.5}$ Plan concerning ammonia emissions and potential control options for agricultural sources.[46] However, we did not elaborate in the 2021 Proposed Rule as to why we proposed to agree that 30% was a reasonable upper bound.

We stated that ambient $PM_{2.5}$ responses to ammonia emission reductions decline over time, and in concert with the large projected $NO_X$ emission reductions, with the largest declines occurring at sites with highest projected $PM_{2.5}$ levels. For the two sites (Madera and Hanford) where the State's modeled response in 2024 to a 30% ammonia emission reduction exceeded the recommended 0.2 μg/m³ threshold, we evaluated additional information and, based on that information, gave the modeled projected responses above the threshold at these sites less weight.

We also considered studies cited by CARB on the 2013 DISCOVER–AQ aircraft measurements and 2017 satellite measurements, both of which suggest that ammonia concentrations are underestimated in the SJV. We noted that if modeled ammonia concentrations were closer to observations, then the modeled response to ammonia precursor reductions would be lower than shown in the 2018 $PM_{2.5}$ Plan's precursor demonstration. Similarly, an increase in modeled ambient ammonia concentrations would also make the model response more consistent with the evidence from the multiple ambient measurement studies that suggest a very low ambient sensitivity to ammonia, based on measured excess ammonia relative to $NO_X$, the abundance of particulate nitrate relative to gaseous $NO_X$, and the large abundance of ammonia relative to nitric acid. These ambient measurement studies all conclude that there is a large amount of ammonia left over after reacting with $NO_X$, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate, and thus provided strong evidence independent of the modeling that ambient $PM_{2.5}$ levels would respond comparatively weakly to ammonia emissions reductions.

Regarding changes in the effect of ammonia emission reductions over time as other pollutant levels change, we stated it was appropriate to consider changes in atmospheric chemistry that may occur between the base or current year and the attainment year because the changes may ultimately affect the nonattainment area's progress toward expeditious attainment. We stated that the 2024 model results would in this case better represent the point in time at which it is appropriate to evaluate what potential ammonia controls could achieve, because of the steep decline in $NO_X$ emissions the State projects will occur by 2024 and 2025 as a result of existing or intended control measures. We also noted that the projected annual average $PM_{2.5}$ concentration of 12.0 μg/m³, occurring at the Bakersfield-Planz monitoring site in 2025, would be reduced by 0.12 μg/m³, which would not be considered significant (it is below the EPA's recommended threshold of 0.2 μg/m³).

In sum, we concluded that the State had evaluated the sensitivity of ambient $PM_{2.5}$ levels to potential reductions in ammonia emissions using appropriate modeling techniques; the modeled response to ammonia reductions is likely lower than reported; and the State's choice of 2024 and 2025 as the reference points for purposes of evaluating the sensitivity of ambient $PM_{2.5}$ levels to ammonia emission reductions was well-supported. Based on all of these considerations, the EPA previously proposed to approve the State's demonstration that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

2. Summary of Adverse Comments

Public Justice states that the ''EPA must disapprove the ammonia precursor demonstration'' and that ''CARB's tortured analysis (and EPA's proposed acceptance of it)'' is arbitrary and capricious. The commenter makes several assertions in support of this comment.[47]

First, Public Justice notes that CARB's analysis concluded that ammonia contributes 5.2 μg/m³ to annual average $PM_{2.5}$ concentrations, and that this is well above the EPA's recommended annual average contribution threshold of 0.2 μg/m³.[48] The commenters also

[45] Id. at App. G, 5.

[46] EPA's $PM_{2.5}$ Precursor TSD, 13.

[47] Public Justice Comment Letter, 16–18.

[48] The commenters note that 38% of the annual average ambient $PM_{2.5}$ in Bakersfield is ammonium nitrate. Public Justice Comment Letter, 6. See also, 2018 $PM_{2.5}$ Plan, Ch. 3, Figure 3–2 (''Bakersfield $PM_{2.5}$ Speciation (Average 2011 to 2013)'').

took issue with CARB and the EPA's arguments that such results overstate the role of ammonia because $NO_X$ emissions decline over time, and the EPA's decision to look at the results of sensitivity modeling for the response of ambient $PM_{2.5}$ levels to potential ammonia emission reductions in the future year 2024. The commenters assert that this analytical approach of considering the projected sensitivity to ammonia reductions in the future year ''ignores the statutory imperative to demonstrate attainment as expeditiously as practicable,'' per CAA section 172(a)(2)(A), and that, even after evaluating the impact ''for the most favorable date'' (2024), CARB still found significant contribution for ammonia above the EPA's recommended threshold.

Second, Public Justice questioned CARB's reliance and the EPA's proposed acceptance of a sensitivity analysis that assumed only a 30% modeled reduction of ammonia emissions. Public Justice points out that the EPA's guidance for precursor demonstrations suggests that states should evaluate the effect of reducing emissions between 30% and 70%, and states that ''CARB argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite large ammonia sources (*e.g.,* ''industrial dairy and poultry operations'') never having been regulated in the SJV and the prospect for relatively easier and cheaper emission reductions than those for $NO_X$.[49] The commenters argue that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for reducing PM concentrations,'' and cite several studies in support of this argument. The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[50] The commenters state that agriculture is responsible for over 80% of ammonia emissions, and that confined animal facilities (CAFs) and fertilizer application account for 57% and 36%, respectively.[51] Moreover, the commenters assert that ''[n]o real analysis of control potential is offered'' in the State's precursor demonstration.

Third, with respect to the State and the EPA's evaluation of modeled ambient $PM_{2.5}$ responses to ammonia emission reductions in 2024, Public Justice states that, in the low (30%) emission scenario, 2 of 15 monitoring sites have responses over the 0.2 μg/m$^3$ recommended threshold and that the EPA argues ''with extremely biased evidence, that the results at one of the two monitors could be ignored and that ammonia emissions area likely underestimated.'' The commenters assert that ''EPA points to evidence that 'the State did not discuss' to discount the results'' for the Madera monitor, and that the EPA ''offers no excuse for discrediting the results at the other monitor.''

Fourth, the commenters claim that the EPA's evaluation of the precursor demonstration looked at supplemental ammonia emission studies but ignored supplemental studies showing that $NO_X$ emissions from soil (''soil $NO_X$'') may be significantly underestimated. Public Justice states that the State and the EPA ''assert that $NO_X$ emissions will be significantly reduced by 2024 even though the Plan currently does not explain how those $NO_X$ reductions will occur.'' The commenters state that such approach is ''a one-sided attempt to explain away modeled results that ammonia contributes significantly to $PM_{2.5}$'' in the SJV and cannot overcome the Act's presumption that precursors must be controlled.

Finally, beyond the assertion that the State's precursor demonstration with respect to ammonia, and the EPA's proposed approval of it are incorrect, the commenters also argue that the State's failure to address ammonia as a precursor to $PM_{2.5}$ has disparate impacts on certain communities within SJV and ''avoids difficult political fights by sacrificing communities of color.'' Finally, the commenters refer to a 2021 research study that estimates that 1,690 people in California die annually due to agricultural ammonia emissions.[52]

3. The EPA's Reconsidered Proposal

The EPA agrees with certain points made by the commenters with respect to ammonia and disagrees with others. Overall, based on the adverse comments from Public Justice and a re-evaluation of the information provided by the State, we now conclude that the weight of evidence is insufficient to establish that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS in the SJV. The EPA's further evaluation indicates that it is appropriate to retain the statutory presumption that ammonia must be regulated as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. Accordingly, if the EPA finalizes disapproval of the State's ammonia precursor demonstration, ammonia would remain a plan precursor, and the SJV would remain subject to the requirements to identify and implement BACM, BACT, and additional feasible measures on sources of ammonia emissions.

We first address the portion of the comment related to the sensitivity of the modeled $PM_{2.5}$ response to reductions in ammonia emissions and then turn to the portion of the comment addressing the amount of ammonia reductions that may be available.

a. Comments Related to Sensitivity Modeling Results

The measured ammonium nitrate portion of the annual average $PM_{2.5}$ concentration in Bakersfield in 2015 was 5.2 μg/m$^3$.[53] This is well above the EPA's recommended threshold in the $PM_{2.5}$ Precursor Guidance. However, the $PM_{2.5}$ SIP Requirements Rule, as interpreted by that guidance, provides the option for a State to conduct an analysis of the sensitivity of ambient $PM_{2.5}$ concentrations to emission reductions of a precursor pollutant to evaluate the significance of that precursor,[54] as the State did for the 2012

[49] Public Justice Comment Letter, 2, 5, and 16–17, and Exhibits 31 through 34.

[50] Public Justice Comment Letter, 16–17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[51] Public Justice Comment Letter, 5–6, 16, citing See EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.'' We note that our TSD in turn cited to State data sources, including the 2018 $PM_{2.5}$ Plan, App. G, Figure 3.

[52] Public Justice Comment Letter, 18. See Domingo, N.G.G., Balasubramanian, S., Thakrar, S.K., Clark, M.A., Adams, P.J., Marshall, J.D., Muller, N.Z., Pandis, S.N., Polasky, S., Robinson, A.L., Tessum, C.W., Tilman, D., Tschofen, P., & Hill, J.D., ''Air quality–related health damages of food,'' Proceedings of the National Academy of Sciences (Vol. 118, Issue 20, p. e2013637118), 2021, available at *https://doi.org/10.1073/pnas.2013637118,* attached as Exhibit 35. See **SUPPLEMENTARY INFORMATION** for ''Air quality-related health damages of food,'' Table S2 (''Annual emissions and mortality caused by agricultural production in the 10 states where emissions of (A) primary $PM_{2.5}$, (B) $NH_3$, (C) $NO_X$, (D) $SO_2$, and (E) NMVOCs lead to the highest total mortality'').

[53] 86 FR 74310, 74318 and 2018 $PM_{2.5}$ Plan, App. G, 3.

[54] 40 CFR 51.1006(a)(1)(ii).

annual $PM_{2.5}$ NAAQS in the SJV. Thus, the concentration-based contribution analysis alone (*i.e.,* the 5.2 μg/m$^3$) is not necessarily determinative of a precursor's significance.

The commenters stated that reliance on a sensitivity-based test for 2024 ignores the statutory imperative for expeditious attainment. But, as noted in the preamble for the $PM_{2.5}$ SIP Requirements Rule in explaining the rationale for a sensitivity-based test, ''if conditions in a particular area are such that control of sources of one or more precursors does not reduce $PM_{2.5}$ concentrations in the area, then those controls will not help the area attain (expeditiously or otherwise).'' [55] Thus, if a precursor demonstration were to show that control of a particular precursor is not effective for reaching attainment, then the absence of such control would not violate the requirement for expeditious attainment.

As commenters noted, the State relied on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor to ambient $PM_{2.5}$ concentrations in the San Joaquin Valley. In our 2021 Proposed Rule, we discussed the State's selection of 2024 as an acceptable analysis year, given the projected steep decline in ambient $PM_{2.5}$ sensitivity to ammonia reductions over time as a result of projected changes in emissions (*i.e.,* large $NO_X$ emission reductions as contemplated in the Plan, through existing measures and aggregate commitments), consistent with the facts and circumstances recommended for consideration in the EPA's $PM_{2.5}$ Precursor Guidance.[56]

The $PM_{2.5}$ Precursor Guidance provides for consideration of sensitivity in an appropriate future year.[57] Based on the State's control strategy, including baseline emission reduction measures and its control measure and aggregate tonnage commitments, the State estimated it would achieve over 200 tpd $NO_X$ reductions by 2024, representing over 60% of the 2013 base year emissions inventory for $NO_X$.[58] Existing baseline measures already in the SIP are projected by the State to reduce annual average $NO_X$ emissions in the SJV by 173.5 tpd, which is 83.7% of the 207.38 tpd of $NO_X$ reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS. Over 90% of the baseline $NO_X$ reductions between 2013 and 2025 are due to the existing mobile source control program.[59] These reductions will occur regardless of any EPA action on the precursor demonstration or the 2018 $PM_{2.5}$ Plan as a whole. Similarly, additional measures adopted by the State through the end of 2021 further reduce $NO_X$ emissions. Given the large $NO_X$ emission reductions projected to occur by 2024 and 2025, the EPA has concluded that that the 2024 sensitivity model results better represent the atmospheric chemistry around the attainment date and in subsequent years than sensitivity modeling results from 2013 and even 2020.[60] Due to continued existing and anticipated $NO_X$ reductions, the apparent $PM_{2.5}$ benefit of ammonia reductions in earlier years declines with time and does not reflect the ultimate, lower, benefit of such controls near the attainment year and later.

Thus, the EPA reasons that the Plan's baseline and additional control measures will change (and have already changed) the atmospheric chemistry conditions in the SJV, leading to ambient $PM_{2.5}$ formation that is much less sensitive to ammonia emission reductions in the attainment year. We maintain that the State's reliance on its sensitivity-based contribution analysis for 2024 to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the $PM_{2.5}$ SIP Requirements Rule and EPA guidance.

The commenter correctly states that 2 of 15 sites in the 2024 model scenario based on a 30% reduction in ammonia emission were modeled to have an ambient $PM_{2.5}$ response greater than the EPA's recommended contribution threshold of 0.2 μg/m$^3$. However, we disagree with the commenter's characterization that our further review of the sensitivity of the Madera and Hanford sites to ammonia emission reductions was argued ''with extremely biased evidence.'' [61]

For the Madera monitor (estimated sensitivity of 0.21 μg/m$^3$ in 2024 to a 30% ammonia emission reduction), the commenter refers to the EPA's statement that the 2018 $PM_{2.5}$ Plan did not discuss the evidence for the 2013 monitored concentrations at this site being biased high (as a matter of the physical recordings of the monitor). However, the EPA did reference the State's prior analysis of such evidence, which we considered in our evaluation.[62] Aside from pointing out that this analysis was not included in the Plan itself, the comment does not offer analysis to the contrary, and the EPA continues to think that we reasonably weighed the technical information before us and, given the role of the 2013 monitored data in the sensitivity modeling conducted by the State, correctly concluded that ''if more typical Madera concentrations were used, it is likely that the 2024 Madera response to ammonia reductions would be below the contribution threshold'' and that the extra year of $NO_X$ reductions from 2024 to 2025 would likely decrease the sensitivity below the recommended 0.2 μg/m$^3$ threshold.

We further disagree with the commenter's assertion that we offered no reason for giving less weight to modeled sensitivity results for the Hanford monitor (estimated sensitivity of 0.26 μg/m$^3$ in 2024 to a 30% ammonia emission reduction). We stated that we gave both Madera and Hanford modeled sensitivity lower weight in our overall assessment of ammonia as a precursor. Specifically for Hanford, we described evidence that the modeled sensitivity there was likely overestimated. That evidence included an independent study using data from the 2013 DISCOVER–AQ campaign that ''found that the [CMAQ] model underestimated ammonia at Hanford by a roughly a factor of four or five.'' [63] In our assessment, if the model's ammonia concentrations better matched the observations then there would be more of an ammonia excess in the model, and the modeled response to ammonia reductions would be lower.

More broadly, prior to publishing the 2021 Proposed Rule, the EPA reviewed available research including from supplemental materials from CARB, and found a consistent theme based on modeling analyses and ambient measurement studies—that ''there is a large amount of ammonia left over after reacting with $NO_X$, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate.'' [64] It is important to note that this ammonia excess is *measured,* and is independent

[55] 81 FR 58010, 58025.

[56] 86 FR 74310, 74320–74321 and $PM_{2.5}$ Precursor Guidance, 35.

[57] $PM_{2.5}$ Precursor Guidance, 35.

[58] 86 FR 74310, 74327, Table 4.

[59] 2018 $PM_{2.5}$ Plan, App. B, Table B–2.

[60] We address the potential impact of ammonia emissions on the requirement for expeditious attainment in our re-evaluation of the attainment demonstration in section II.C.3, below.

[61] Public Justice Comment Letter, 18.

[62] 86 FR 74310, 74320, fn. 91, and fn. 92. This analysis concluded that 2011–2013 Madera data did not fit the geographic pattern historically seen in relation to other monitors but returned to the historic pattern after corrections were made to the monitoring instrument operating procedures. Concentrations were estimated to be about 10% high during the period in question.

[63] 86 FR 74310, 74320.

[64] Id. See also, EPA's Ammonia Precursor TSD.

of any assumptions about the size of the ammonia or $NO_X$ emissions inventories, and also independent of any uncertainties in the modeling exercise. The concerns raised by Public Justice about relative levels of ammonia and $NO_X$ estimation are not sufficient to cause the EPA to revise the conclusion that $PM_{2.5}$ is likely to have low sensitivity to ammonia reductions, which is supported by the actual observed conditions. The ambient measurement evidence is strong and leads the EPA to believe that the modeled response to ammonia in the State's precursor demonstration may be overestimated. Therefore, we maintain that the EPA may give lower weight to the modeled sensitivities of ambient $PM_{2.5}$ concentrations to ammonia emission reductions at the Madera and Hanford sites.

The commenter states that the EPA's argument on the relative levels of ammonia and $NO_X$ emissions looks at such ammonia studies but ''ignores supplemental studies showing that . . . soil $NO_X$ emissions [may be significantly underestimated].'' [65] Unlike the general consensus in the ammonia studies described above, with respect to the amount of $NO_X$ emitted by soil in the SJV the EPA believes that there is conflicting research. A conclusion of Almaraz et al. (2018) and Sha et al. (2021) cited by the commenters is that soil $NO_X$ emissions are underestimated, and that they comprise 30–40% of total $NO_X$ emission in California. While higher levels of soil $NO_X$ (or $NO_X$ more generally) would tend to increase the modeled sensitivity of ambient $PM_{2.5}$ to ammonia, we maintain that there is not a sufficient basis to conclude that higher soil $NO_X$ emissions should be used in the air quality modeling for the SJV.[66]

In contrast to the studies just cited, Guo et al. (2020) [67] did not find such a discrepancy in emissions estimates, concluding that soil $NO_X$ is about 1% of anthropogenic $NO_X$ emissions. The fraction of nitrogen applied as fertilizer released as $NO_X$ to the atmosphere was estimated by Almaraz et al. to be 15%, while seven other studies reviewed by Guo et al. estimated it to be 2% or less. Yet Almaraz et al., Sha et al., and Guo et al. all reported high agreement between their modeled and observed soil $NO_X$ emissions. The Almaraz et al. study acknowledged the limited number of surface measurements that were available for purposes of comparing the model results and the difficulty in comparing the model results to the observations and noted the need for more field measurements. Guo et al. stated that obtaining an emission factor correlating $NO_X$ emissions to fertilizer application from the data available in various studies (including Almaraz et al.) would be ''difficult or impossible'' due to the sparsity of data collected in terms of sampling length, sampling frequency, and the episodic nature of nitrogen gas emissions from soil.

In light of the uncertainties and disagreements among studies, the EPA does not believe that available research provides sufficient certainty about the magnitude and proportion of soil $NO_X$ emissions attributable to agricultural fertilizer application to require substantial revisions in the $NO_X$ emissions inventory nor the $PM_{2.5}$ modeling at this time.

In addition, as just described, multiple studies of ambient measurements show excess ammonia in the atmosphere, which is strong evidence of low sensitivity to ammonia reduction that is independent of the accuracy of estimates of precursor emissions from any source, including soil $NO_X$, and independent of any modeling. Thus, we disagree that the EPA ''ignored'' the supplemental soil $NO_X$ studies; we were aware of and considered them, but they did not change our conclusion.

b. Comments Related to Scale of Potential Ammonia Emission Reductions

The 2018 $PM_{2.5}$ Plan includes modeling of 30% and 70% reductions in ammonia emissions and focuses on the results of the 30% reduction based on the assertion that the area could not achieve more than a 30% decrease in ammonia emissions. Public Justice questions the basis for the assertion that no more than 30% reductions are available. In this section, we examine, based on the submission, the $PM_{2.5}$ Precursor Guidance, and the Public Justice comment, the ammonia reductions that may be available in the SJV. Specifically, we explore the uncertainty with respect to both the current state of ammonia emissions and controls in the SJV and available research examining additional control options that may be available. We conclude that, based on the information before us, the 2018 $PM_{2.5}$ Plan does not provide sufficient support for the assertion that 30% is a reasonable upper bound on available ammonia reductions in the SJV.

The District presented its analysis of ammonia control for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The EPA had reviewed this analysis for our assessment in the 2021 Proposed Rule that 30% was, for analytical purposes, a reasonable upper bound for ammonia emission reductions in the SJV, and referred to prior EPA analysis for our action on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan.[68] In evaluating the Public Justice comments on the potential control of ammonia, however, we have re-evaluated other portions of the 2018 $PM_{2.5}$ Plan, including Appendix C, section C.25 and Appendix G,[69] and reviewed the studies cited by the commenters, as well as others from the EPA's own literature search.

As noted in the EPA's $PM_{2.5}$ Precursor Guidance,[70] and consistent with the $PM_{2.5}$ SIP Requirements Rule (40 CFR 51.1010(a)(2)(ii), 51.1006(a)(1)(ii)), the EPA may require the State to identify and evaluate potential control measures for a precursor to determine the potential emissions reductions achievable, as a part of the precursor analysis. The guidance states that this evaluation is particularly important when the $PM_{2.5}$ response to a 30% reduction in precursor emissions is close to the contribution threshold. In the case of a nonattainment area classified as Serious, this analysis would include identification and evaluation of measures that would constitute BACM/BACT level controls for such pollutant.[71]

[65] Public Justice Comment Letter, 18. Public Justice cited Almaraz et al. (2018), ''Agriculture is a major source of $NO_X$ pollution in California,'' Science Advances, 4(1), doi:10.1126/sciadv.aao3477, 2018, available at *https://advances.sciencemag.org/content/4/1/eaao3477;* and Sha et al. (2021), ''Impacts of soil $NO_X$ emission on $O_3$ air quality in rural California,'' Environmental Science & Technology, 55(10), 7113–7122, available at: doi:10.1021/acs.est.0c06834; available at *https://pubs.acs.org/doi/10.1021/acs.est.0c06834.*

[66] See also, EPA Region IX, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020, 148 and 158.

[67] Guo et al. (2020), ''Assessment of Nitrogen Oxide Emissions and San Joaquin Valley $PM_{2.5}$ Impacts From Soils in California,'' Journal of Geophysical Research: Atmospheres, 125(24), doi: 10.1029/2020JD033304; available at *https://doi.org/10.1029/2020JD033304.*

[68] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and EPA's $PM_{2.5}$ Precursor TSD, 13.

[69] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. G, 13, where CARB states that ''CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (*i.e.,* 30 percent), much less at the upper end of the range.''

[70] $PM_{2.5}$ Precursor Guidance, 31.

[71] The $PM_{2.5}$ Precursor Guidance provides: ''[c]onsistent with the $PM_{2.5}$ SIP Requirements Rule, the EPA may in some cases require air agencies to evaluate available emissions controls in support of a precursor demonstration that relies on a

Even when the modeled responses are below the recommended 0.2 µg/m³ contribution threshold, or when particular responses are given less weight as we have discussed above for Madera and Hanford, the outcome of a sufficiently thorough controls evaluation and its conclusions on achievable emissions reductions may be important information for the EPA to consider in deciding whether to approve the precursor demonstration. Here, the State's ammonia precursor demonstration strongly relies on the assertion that no more than 30% ammonia reductions below current levels is achievable, but there is not a sufficiently thorough controls evaluation to support that assertion. Because the 30% value has not been adequately supported, the EPA cannot evaluate whether the modeled $PM_{2.5}$ reductions associated with a 30% reduction in ammonia represent the reductions that may be possible in the SJV.

The EPA also emphasizes that the 30% control threshold is part of an analytical test to help evaluate whether the State must regulate ammonia as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the area; it does not mean that if the State cannot control 30% of ammonia with BACM/BACT-level controls that there is per se no need to regulate ammonia. For example, if control of 25% of ammonia is necessary for attainment of the $PM_{2.5}$ NAAQS, then the fact that this is below 30% is irrelevant. Our attention to the 30% threshold in this notice is to help interpret the $PM_{2.5}$ responses to modeled ammonia emissions reductions in the State's precursor demonstration, which modeled a 30% reduction. This point is important analytically because, insofar as potential ammonia reductions could be larger than 30%, the modeled responses could be larger than those relied upon in the State's precursor analysis to support its determination that ammonia is not a significant precursor.

With respect to the State's assertion that 30% is a reasonable upper bound for potential ammonia emission reductions, we agree with the commenters that the analysis of potential ammonia controls provided by the State and the evaluation of that information by the EPA lacked detailed support and is not a sufficient basis for the EPA to affirm that 30% is a reasonable upper bound for potential ammonia emission reduction in the SJV. This, in turn, affects the EPA's interpretation of the results of modeled responses to ammonia reductions. There are two general deficiencies in the submitted analysis that create uncertainty as to the potential for ammonia emission reductions, as discussed below: (1) incomplete quantification of existing ammonia emission reductions from the largest sources of ammonia; and 2) incomplete consideration and evaluation of potential additional controls of ammonia emissions for sources in the SJV. We walk through these uncertainties for each of the largest sources of ammonia in the SJV (*i.e.,* CAFs and fertilizer application).

As an initial matter, the commenters state that ''[the State] argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite major ammonia sources never having been regulated in the SJV and the relatively easier and cheaper sources of emission reductions relative to $NO_X$. We understand this reference to ''major ammonia sources'' to mean the main source categories of ammonia emissions in the SJV, including CAFs and fertilizer application, which the State estimated to emit 57% and 36%, respectively, of the annual average ammonia emissions in the SJV in 2013.[72]

We agree with the commenters that neither CARB nor the District have imposed controls specifically to regulate ammonia. We note, however, that ammonia-specific controls are not required for approval of an ammonia precursor demonstration. Moreover, although there are not ammonia-specific controls in place for the largest source categories in the SJV, many sources of ammonia are in fact regulated by District rules, such as Rule 4570 (''Confined Animal Facilities''), Rule 4565 (''Biosolids, Animal Manure, and Poultry Litter Operations''), and Rule 4566 (''Organic Material Composting Operations''), which include enforceable requirements for VOC emissions that would, in general, achieve some degree of ammonia emission reductions. We agree with the general assertion, presented by the District in section C–25 (''Ammonia in the San Joaquin Valley'') of Appendix C of the 2018 $PM_{2.5}$ Plan, that some management practices to reduce VOCs in those rules also collaterally reduce ammonia emissions by limiting ammonia formation and volatilization, even though ammonia reductions are not legally required by these measures.[73]

Although we expect that existing VOC regulations are achieving a degree of ammonia control, there are multiple reasons why it is not clear, based on the record before us, how much reduction is being achieved, and thus how much additional reduction may be available. For example, regarding CAFs, as the EPA has previously noted,[74] the State has not sufficiently substantiated its calculation of 100 tpd of ammonia emission reductions attributed to Rule 4570. In the 2018 $PM_{2.5}$ Plan, the State referenced an outdated analysis from 2006 that relied on a different baseline emissions inventory, but has not supplemented this analysis, or reconciled it with more recent emissions inventory data.[75] We note that CARB has provided the EPA with significantly lower estimates of ammonia emission reductions achieved by SJVUAPCD Rule 4570 based on more recent calculations of reductions from a 2012 baseline emissions inventory.[76] The 2018 $PM_{2.5}$ Plan does not reconcile these differences, nor update the emission reduction estimate from the 2006-era analysis to the emissions inventory basis of the 2018 $PM_{2.5}$ Plan.

sensitivity analysis. [See 40 CFR 51.1009(a)(2) and 51.1010(a)(2).] It is particularly important for states to evaluate available controls where the recommended contribution threshold—that is, the threshold used for identifying an impact that is 'insignificant'—is close to being exceeded at the low end of the recommended sensitivity range (*e.g.,* 30 percent). In these cases, the EPA may determine that to sufficiently evaluate whether the area is sensitive to reductions, the State must determine the potential precursor emission reductions achievable through the implementation of available and reasonable controls for a Moderate area (or best controls for a Serious area).'' $PM_{2.5}$ Precursor Guidance at 31.

[72] See Public Justice Comment Letter, 6, citing EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.''

[73] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. C, C–313 (for CAFs). The lack of controls specifically regulating *ammonia emissions* from the largest source categories through enforceable SIP requirements in the SJV is not an inherent deficiency of the precursor demonstration, but it does result in challenges for determining the potential for ammonia emission controls (*i.e.,* in determining the reductions that have already been achieved, and what additional reductions are available).

[74] 81 FR 69396, 69397–69398 (October 6, 2016).

[75] 2018 $PM_{2.5}$ Plan, App. C, C–311 to C–339 and SJVUAPCD, ''Final Draft Staff Report, Proposed Re-Adoption of Rule 4570 (Confined Animal Facilities),'' June 18, 2009, at Appendix F, ''Ammonia Reductions Analysis for Proposed Rule 4570 (Confined Animal Facilities),'' June 15, 2006 (discussing various assumptions underlying the District's calculation of ammonia emission factors without identifying relevant emissions inventories).

[76] Email dated September 3, 2015, from Gabe Ruiz, CARB, to Larry Biland and Andrew Steckel, EPA Region IX, regarding ''SJV Livestock Ammonia Emissions with and without Rule 4570.'' This email notes that 2011 ammonia emissions (pre-rule) were 316.8 tpd, 2012 emissions (without rule) were 323.8 tpd, and 2012 emissions (with rule) were 250.9 tpd. Thus, application of Rule 4570 would have achieved either 72.9 tpd of ammonia reductions, measured within 2012 with and without the rule, or 65.9 tpd, measured from the 2011 level (without rule) to the 2012 level (with rule).

In short, although we agree that some existing VOC controls will also result in ammonia reductions, a more detailed analysis it required to determine both the effectiveness of existing controls, and the additional controls that may be available. In the following, the EPA notes various uncertainties concerning ammonia emissions and in the amount of reductions achieved by specific rules as a byproduct of the existing VOC control measures. For a number of key source categories, ammonia measures require additional analysis to evaluate their potential to achieve additional emissions reductions, in part based on research studies included as exhibits to the Public Justice Comment Letter.

For CAFs, the District discusses in detail how Rule 4570 is structured (*e.g.,* to address varying types of CAFs); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; the control menu requirements for each of those five operations; and research papers that estimate ammonia emission reductions from some of the measures.[77] However, the 2018 $PM_{2.5}$ Plan does not specify, even in an aggregated form, which control measures were selected by CAFs in their permits-to-operate with the District for each of the five operations and the scale of those selections by CAF size, nor does it quantify the emission reductions from those selections and scales. Thus it is unclear what level of ammonia control is being achieved, and, importantly for the precursor demonstration, unclear what level of further ammonia control may be possible. This uncertainty is increased by several provisions in Rule 4570 that allow CAF owners/operators to implement ''alternative mitigation measures'' [78] *in lieu of* the mitigation measures listed in the rule, without any requirement to ensure that such alternative mitigation measures achieve any particular level of ammonia emission reductions, or any ammonia reductions at all.[79]

Furthermore, for certain requirements, the 2018 $PM_{2.5}$ Plan assumes that a less effective control measure may be implemented given that the more effective control measure may be more costly. For instance, the District describes some research studies that relate to one or more of the options, but it is not clear whether and how the requirements of each option align with the practices evaluated in each study. The District cites a 2005 University of California study that manure from lagoons, diluted with irrigation water, and applied via surface gravity irrigation systems (*e.g.,* not applied with a drag hose or similar apparatus) commonly minimized ammonia losses from volatilization to the air to 10% or less.[80] However, it is not clear how the requirements of option H.2.a (liquid manure treated in an aerobic or anaerobic lagoon) or option H.2.b (24-hour limit for liquid manure standing on fields) may correspond to the study, whether any particular level of lagoon treatment or dilution prior to application would be needed, nor whether a combination of the two would be required to minimize ammonia losses to air to that degree.

For option H.2.c, the District states that use of a drag hose or similar apparatus could significantly reduce ammonia emissions, but without specifying how much or pointing to any supporting document, and only qualitatively asserting a relatively higher cost for using such equipment, and its limitations when a crop is growing.[81] The District states that ''[a]pplication of liquid or slurry manure with a drag hose or similar apparatus could result in significant [ammonia] reductions, but has higher costs compared to flood or furrow irrigation of liquid manure.'' [82] However, higher cost does not necessarily translate to the measure being economically infeasible, and thus the option to use flood or furrow irrigation alone may not represent the most appropriate method or level of control of ammonia for the land application of liquid manure. As a result, the District has not demonstrated that additional reductions are not feasible.

The District assumes that all dairies and other cattle facilities would select option H.2.b (24-hour limit for liquid manure standing on fields) and cites two studies that suggest substantial ammonia emission reductions from this limitation, assuming no ammonia emissions into the air after soil incorporation.[83] Based on one study, dairy CAF operations in the SJV would have hypothetically already reduced ammonia emissions to the air from land application of liquid manure from 66% ammonium nitrogen to 25% ammonium nitrogen by implementing option H.2.b (a 41% absolute reduction, or 62% relative reduction). Uncertainty about the options that are being chosen and implemented by regulated entities gives rise to uncertainty in the ammonia emission reductions that are being achieved. The permits-to-operate submitted by each dairy CAF are required to indicate which option has been selected.[84] Accordingly these permits, and associated compliance records, should contain information that would help to address this uncertainty. Furthermore, if injection via drag hose or similar apparatus (option H.2.c) is economically feasible, even if more expensive, implementation of such a measure could further reduce ammonia by 25% based on the same study, at least for a portion of the operating cycle (*e.g.,* when crops are not growing). Lastly, a combination of measures (*e.g.,* requiring that liquid manure be both treated in an anaerobic lagoon, aerobic lagoon, or digester, and that it be incorporated into the soil within 24 hours) or adjustment to existing options (*e.g.,* requiring incorporation of liquid manure within 6 hours, rather than 24 hours, and during cooler hours when ammonia volatilization is less) could hypothetically reduce ammonia emissions at these sources by more than 30%.[85]

In general, with respect to dairy CAFs, on a qualitative basis CAF operators have likely reduced ammonia emissions

[77] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[78] ''Alternative Mitigation Measure'' is defined in SJVUAPCD Rule 4570 as ''a mitigation measure that is determined by the APCO, [CARB], and EPA to achieve reductions that are equal to or exceed the reductions that would be achieved by other mitigation measures listed in this rule that owners/operators could choose to comply with rule requirements.'' SJVUAPCD Rule 4570 (amended October 21, 2010), section 3.4. Because SJVUAPCD Rule 4570 explicitly applies only to VOC emissions, the requirement for equivalent ''reductions'' in section 3.4 applies only to VOC emission reductions and does not apply to ammonia emission reductions.

[79] See, *e.g.,* SJVUAPCD Rule 4570 (amended October 21, 2010) at section 5.6, Table 4.1.F.

[80] University of California, Division of Agricultural and Natural Resources, Committee of Experts on Dairy Manure Management, ''Managing Dairy Manure in the Central Valley of California,'' June 2005.

[81] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to a 2008 report by Alberta Agriculture and Food (Canada). Albert Agriculture and Food, ''Ammonia Volatilization from Manure Application,'' February 2008 (''2008 Alberta Report''). That report estimates that injection into soil would reduce the average ammonium-nitrogen fraction loss (*i.e.,* to air) to 0% compared to incorporation within one day from surface application (25%) or compared to surface application with no incorporation (66%). 2008 Alberta Report, Table 2.

[82] 2018 $PM_{2.5}$ Plan, App. C, C–322 to C–323.

[83] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to two studies: the 2008 Alberta Report, and Chadwick et al. ''Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering,'' Atmosphere Environment, 39: 787–799 (2005); available at: *http://www.sciencedirect.com/science/article/pii/S135223100400994X.*

[84] Under District Rule 4570, section 5.1, owners/operators of CAFs subject to the rule must obtain a permit-to-operate for the facility, and that permit must include a facility emission mitigation plan, a facility emission inventory, and identify the mitigation measures selected for the facility.

[85] 2008 Alberta Report.

to a degree consistent with the options selected. However, there is not a quantitative basis to specify the degree and potential for further reduction. For some of the options within the menu of mitigation measures for each type of CAF in Rule 4570, there are research studies to support the basis of existing ammonia emission reductions. The generalized assumptions used by the State could be evaluated by an analysis of the options selected by CAFs in permits-to-operate with the District. Further assessment of available compliance records and examination of combinations of measures or adjustments to existing measures could help quantify additional potential ammonia emission reductions.

In addition, Public Justice cites several studies to support its assertion that reductions in agricultural ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' and cites several studies to support this assertion.[86] The EPA considers these approaches to warrant examination as potential means to reduce ammonia and believes that more information regarding their efficacy as control measures and their economic and technical feasibility is needed to determine the amount of the potential additional ammonia control in the SJV.

For livestock feed, studies in 2005 and 2006 cited by the commenter found that ''decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.'' [87] A 2009 study cited by the commenter found that ''one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (NH3–N/head/day) over nine months, compared with 82 g NH3–N/head/day at another feedyard feeding lower protein steam-flaked, corn-based diets.'' [88] Nominally this would represent a 45% reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein intake on the time for beef cattle to reach market weight or on milk production for dairy cattle.

For manure handling and storage practices, a 2011 inventory of mitigation methods by Price et al. identifies many mitigation methods for various kinds of CAFs, some of which may reduce ammonia emissions by 50–90%.[89] For example, Method 44 (''Washing down dairy cow collecting yards'') involves areas where dairy cows are collected on a concrete yard prior to milking and, after each milking event, the urine and manure in the area are removed by pressure washing or by hosing and brushing, resulting in up to 90% ammonia emission reductions. Method 62 (''Cover solid manure stores with sheeting'') involves covering solid manure heaps with plastic sheeting, resulting in ammonia emission reductions up to 90%.[90] However, the authors note that, for both Method 44 and Method 62, reducing ammonia emission from the milking areas would increase the ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading, but by a lower amount than the initial reduction amount. Method 71 (''Use slurry injection application techniques'') involves shallow (5–10 cm depth) or deep (25 cm depth) injection of slurry into the soil, resulting in ammonia emission reductions of 70% to 90%, respectively.

Mitigation methods are also described for other kinds of CAFs, such as pig farms and chicken farms. For example, Method 48 (''Install air-scrubbers or biotrickling filters to mechanically ventilated pig housing'') involves pig housing where specific technologies are used to capture up to 90% of the ammonia emissions into recirculation water that can then be used as a nitrogen-based fertilizer. Method 51 (''In-house poultry manure drying'') involves installation of ventilation/drying systems that reduce the moisture content of poultry litter, resulting in up to 50% ammonia emission reductions, though, as with the cattle examples, this could result in some increased emissions at subsequent steps (*e.g.,* storing poultry litter).

In addition to the 2011 inventory of mitigation methods, in September 2017, the EPA and the U.S. Department of Agriculture, Natural Resource Conservation Service released the ''Agricultural Air Quality Conservation Measures, Reference Guide for Poultry and Livestock Production Systems'' (2017 EPA–USDA Reference Guide). This reference guide discusses air quality conservation measures relating to nutrition and feed management, animal confinement, manure management, land application, and other supplemental practices. Among other things it includes Appendix A.1 (''Table of Mitigation Effectiveness for Selected Measures''), which lists 12 measures that may reduce ammonia emissions by more than 30%, Appendix A.2 (''List of State Programs and Regulations for AFO Air Emissions''), and Appendix A.3 (''List of AFO Air Quality Programs & Land-Grant Universities'').

In sum, various research studies on mitigating ammonia emissions from CAFs suggest that there may be potential for additional ammonia reductions from activities such as animal feeding and housing to manure storage, handling, and land application. While the Plan refers to and describes some of the research studies described herein (*e.g.,* the 2008 Alberta Report and the 2005 Chadwick paper), it is unclear the extent to which the higher emission reduction measures have been or could be implemented in the SJV and, when aggregated across all CAF operations, it remains unclear whether the total reduction from additional measures would be greater than the State's estimate of maximum available

[86] Public Justice Comment Letter, 16–18.

[87] Public Justice Comment Letter, Exhibit 36, 9. Exhibit 36 is: Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005); and Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[88] Public Justice Exhibit 36, 10, referring to a study by Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. ''Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards.'' In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[89] Public Justice Comment Letter, Exhibit 39. Exhibit 39 is: Price et al., ''An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide,'' December 2011. For mitigation measures that may reduce ammonia emissions by 50–90%, for example, methods 43, 44, 47–51, 54–55, 62, 64, 70–71, and 73–74 on pages 70–71, 74–78, 81–84, 93–94, 105–108, and 110–112 respectively, achievable control efficiencies from these measures in the SJV would depend on an applicability and feasibility review.

[90] We note that District Rule 4570, Table 3.1, section F and Table 4.1, section F provide mitigation measure options for the storage of solid manure and separated solids from large dairy CAFs, including measures that involve covering dry manure piles and separated solids, respectively, outside of pens with a weatherproof covering from May through October. Thus, such mitigation measures, if selected, would not be required for the remaining four months of the year (June through September). Similar mitigation measure options in Rule 4570 for covering dry manure piles apply for beef feedlots, other cattle, swine, poultry, and other CAF types.

reductions.[91] Accordingly, the EPA concludes that the available information in the Plan is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from CAFs, which emit a majority of the ammonia in the SJV.

Regarding fertilizer application, Rule 4570 and Rule 4565 have provisions addressing the land application of manure from CAFs and of biosolids, animal manure, and poultry litter from composting operations (though these lack specific enforceable requirements for ammonia). However, more broadly, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[92] Notwithstanding this statement, the District describes key research assessing nitrogen in California, as well as regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms.[93] These orders subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [94]

The EPA anticipates that such regulations are, in practice, likely to enhance the retention of nitrogen (whether from manure or nitrogen-based chemical fertilizers) for productive purposes in the SJV (*e.g.,* growing crops and enhancing soil health) and limit the loss of nitrogen as pollution to water and air (*e.g.,* potentially reduce ammonia emissions). However, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus render quantification difficult, as with Rule 4570.[95]

In addition, the District states that ''the overall efficiency of nitrogen usage at California farms is expected to increase and emissions of reactive nitrogen, including [ammonia], are expected to decrease significantly.'' We agree that managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the District does not attempt to quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability, nor does it attempt to analyze how much additional reductions may be available. Overall, the EPA finds that the available evidence is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from fertilizer application, the second largest ammonia emission source in the SJV.

c. The EPA's Conclusion for Ammonia Precursor Demonstration

The EPA does not believe that the State has presented sufficient evidence that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS. In the absence of an approved precursor demonstration, ammonia remains a plan precursor subject to the requirements of BACM, BACT, and additional feasible measures.

As discussed in our 2021 Proposed Rule,[96] the modeled response to 30% ammonia emissions reductions is above the EPA's recommended contribution threshold of 0.20 μg/m³ at two monitoring sites, Madera and Hanford, providing evidence that ammonia significantly contributes to $PM_{2.5}$ in SJV. In the previous proposal, we gave those responses less weight, because of specific evidence available for these sites that the responses were overestimated. For Madera, the monitoring data used in estimating the model response are biased high, and therefore the modeled response of 0.21 μg/m³, just above contribution threshold, is likely overestimated. For Hanford, several analyses showed ambient ammonia concentrations are underestimated, and so we believe that the modeled response of 0.26 μg/m³ is likely overestimated. Supporting that conclusion is the evidence from ambient concentrations of excess ammonia relative to nitrate, which suggest that $PM_{2.5}$ responses to reductions of ammonia emissions would be dampened by the $NO_X$-limited nature of ammonium nitrate formation in the SJV.

All of those considerations remain for the current proposal. But in light of comments received and re-evaluation of the available evidence, the EPA believes we should give the Hanford response more weight, because that response would be larger if the ammonia reductions modeled were larger than the 30% assumed in the State's precursor demonstration. The previous subsection gave several examples of the uncertainty and possible underestimation of the ammonia benefit of available control measures to the SJV. The EPA does not believe there is sufficient quantitative evidence to rely on 30% as the amount of achievable reductions, and as the amount to use an upper bound on the ammonia emission reductions modeled in the State's precursor demonstration. A robust controls evaluation could show that a larger amount of reductions is achievable. If it is, then not only would the Hanford modeled response be larger, but additional monitoring sites could have a modeled response above the contribution threshold.

For example, with respect to the modeled 2024 ambient $PM_{2.5}$ responses to a 70% emission reduction, we note that the modeled high site of Bakersfield-Planz would have a response of 0.36 μg/m³, the site with the largest modeled response would be 0.75 μg/m³ at Hanford, and six sites (including Hanford) would have modeled responses greater than 0.5 μg/m³. As a more modest example, interpolating between the available 30% and 70% modeled results, if 32% reductions are achievable, then three additional monitoring sites (Turlock, Merced-S. Coffee St., and Modesto) would reach the 0.2 μg/m³ contribution threshold. The uncertainty over the ammonia response means that we cannot rely on 30% as an upper bound for ammonia emission reductions, and so the weight of evidence shifts relative to that in the 2021 Proposed Rule.

The discussion in this proposed rule, and the heavy reliance in the 2021 Proposed Rule, on the State's use of a 30% upper bound for potential reduction from controls should not be interpreted as establishing a 30% ''bright line'' for deciding whether a precursor should be regulated. The $PM_{2.5}$ Precursor Guidance recommends that 30% to 70% emissions reductions be modeled as a way of implementing the $PM_{2.5}$ SIP Requirements Rule's option in 40 CFR 51.1006(a)(1)(ii) for a State to assess the sensitivity of the atmospheric $PM_{2.5}$ to precursor emission reductions. The sensitivity of the atmosphere to reductions is a separate question from what reductions are achievable from controls; the latter is properly part of the control evaluation for BACM, BACT, and additional feasible measures. However, it is important to note that under 40 CFR

[91] In evaluating the aggregate reductions available across all sub-activities, it may be important to evaluate the extent to which reductions at one sub-activity may affect emissions at other stages of the process.

[92] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[93] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[94] Id. at C–341.

[95] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[96] 86 FR 74310, 74320.

51.1010(a)(2)(ii), the EPA may require a control evaluation to help the EPA evaluate the precursor demonstration. The $PM_{2.5}$ Precursor Guidance explains that the additional information from a control evaluation is particularly important when modeled precursor contributions are close to the threshold for a 30% reduction.[97] But the regulations and guidance do not establish an automatic ''off ramp'' for a State to be discharged from the requirements for BACM, BACT, and additional feasible measures via a showing that achievable reductions are below a particular percentage.

We have no evidence that emission reductions below current emissions levels from BACM on all ammonia sources in the SJV would be as large as 70%, but the lack of a developed record showing what ammonia control measures are feasible and what they could achieve makes it harder for the EPA to assess this point. We also lack sufficient evidence to conclude that reasonable ammonia control measures could achieve no more than 30% reductions, and so cannot rely on that supposition in weighing the modeled responses to reductions and other evidence. Better quantification of the possible ammonia reductions from current levels that could result from additional controls would help resolve this issue. Reconciliation of modeled sensitivity with that expected from ambient studies would also be appropriate.

The EPA has re-examined the 2024 sensitivity analyses to both 30% and 70% ammonia emission reductions in light of the uncertainty that 30% represents a reasonable upper bound for potential ammonia emission reductions. We note that the State modeled 30% reduction scenarios and predicted ambient $PM_{2.5}$ responses above 0.2 $\mu g/m^3$ at 2 of 15 sites in 2024; and modeled the 70% reduction scenarios and predicted responses above 0.2 $\mu g/m^3$ at all monitors in 2024.[98] The EPA maintains that the State's reliance on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the EPA's guidance. There are also good reasons for giving less weight to the modeled responses at the Madera and Hanford sites, although those are tempered by the consideration that there is not good support for limiting the modeled ammonia reductions to 30%, leading to the possibility of larger responses at Hanford and of additional sites with responses above the contribution threshold.

The weight of the evidence, including at least one site above the EPA's recommended contribution threshold and the possibility of additional ones depending on the unknown amount of reductions achievable, favor retaining the presumption that ammonia must be regulated as a $PM_{2.5}$ precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For the reasons explained above, the Plan both indicates that there are levels of ammonia control that could have a significant impact on $PM_{2.5}$ levels at multiple monitors in the SJV and does not dispose the potential availability of ammonia emission reductions at a level that would have such impacts. Therefore, the EPA proposes to disapprove the State's ammonia precursor demonstration for the Serious area requirements for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

### *B. Best Available Control Measures*

#### 1. Statutory and Regulatory Requirements

Section 189(b)(1)(B) of the Act requires for any Serious $PM_{2.5}$ nonattainment area that the State submit provisions to assure that the best available control measures (BACM), including controls that reflect best available control technology (BACT), for the control of $PM_{2.5}$ and $PM_{2.5}$ precursors shall be implemented no later than four years after the date the area is reclassified as a Serious area. The EPA has defined BACM in the $PM_{2.5}$ SIP Requirements Rule to mean ''any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate $PM_{2.5}$ nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ emissions and/or emissions of $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of reasonably available control measures (RACM) on the same source(s).'' [99]

The EPA generally considers BACM a control level that goes beyond existing RACM-level controls, for example by expanding the use of RACM controls or by requiring preventative measures instead of remediation.[100] Indeed, because states are required to implement BACM and BACT when a Moderate nonattainment area is reclassified as Serious due to its inability to attain the NAAQS through implementation of ''reasonable'' measures, it is logical that ''best'' control measures should represent a more stringent and potentially more technologically advanced or more costly level of control.[101] If RACM and RACT level controls of emissions have been insufficient to reach attainment, then the CAA Title I, Part D, subpart 4 provisions for $PM_{2.5}$ nonattainment plans contemplate the implementation of more stringent controls, controls on more sources, or other adjustments to the control strategy necessary to attain the NAAQS in the area. Thus, BACM/BACT determinations are to be ''generally independent'' of attainment for purposes of implementing the $PM_{2.5}$ NAAQS.[102]

Consistent with longstanding guidance provided in the General Preamble Addendum, the preamble to the $PM_{2.5}$ SIP Requirements Rule discusses the following steps for states to use in identifying and selecting the emission controls needed to meet the BACM/BACT requirements of 40 CFR 51.1010:

1. Develop a comprehensive emission inventory of all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors from major and non-major stationary point sources, area sources, and mobile sources;
2. Identify potential control measures for all sources or source categories of emissions of $PM_{2.5}$ and relevant $PM_{2.5}$ plan precursors;
3. Determine whether an available control measure or technology is technologically feasible;
4. Determine whether an available control measure or technology is economically feasible; and
5. Determine the earliest date by which a control measure or technology can be implemented in whole or in part.[103]

The EPA allows states to consider factors such as a source's processes and operating procedures, raw materials, physical plant layout, and potential environmental impacts such as increased water pollution, waste disposal, and energy requirements when

[97] $PM_{2.5}$ Precursor Guidance, 31.

[98] 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[99] 40 CFR 51.1000 (definitions). In longstanding guidance, the EPA has similarly defined BACM to mean, ''among other things, the maximum degree of emissions reduction achievable for a source or source category, which is determined on a case-by-case basis considering energy, environmental, and economic impacts.'' General Preamble Addendum, 42010, 42013.

[100] 81 FR 58010, 58081 and General Preamble Addendum, 42011, 42013.

[101] 81 FR 58010, 58081 and General Preamble Addendum, 42009–42010.

[102] $PM_{2.5}$ SIP Requirements Rule, 58081–58082. See also, General Preamble Addendum, 42011.

[103] 81 FR 58010, 58083–58085.

considering technological feasibility.[104] For purposes of evaluating economic feasibility, the EPA allows states to consider factors such as the capital costs, operating and maintenance costs, and cost effectiveness (*i.e.,* cost per ton of pollutant reduced by a measure or technology) associated with the measure or control.[105] For any potential control measure identified through the process described above that is eliminated from consideration, states are required to provide detailed written justification for doing so on the basis of technological or economic feasibility, including how its criteria for determining such feasibility are more stringent than those used for determining RACM/RACT.[106]

Once these analyses are complete, the State must use this information to develop enforceable control measures for all relevant source categories in the nonattainment area and submit them to the EPA for evaluation as SIP provisions to meet the basic requirements of CAA section 110 and any other applicable substantive provisions of the Act.

2. BACM for Ammonia Sources

As previously noted, as part of the EPA's 2021 Proposed Rule, we reviewed the State's analysis of ammonia control for the primary source categories of ammonia in the context of our evaluation of the State's precursor demonstration.[107] Because our prior proposal to approve the State's ammonia precursor demonstration would have relieved the State of its obligation to implement BACM for ammonia sources, we did not present a summary of the 2018 $PM_{2.5}$ Plan with respect to the BACM requirements for ammonia for the 2012 annual $PM_{2.5}$ NAAQS, nor our evaluation thereof. Given our reconsidered proposal to disapprove the State's ammonia precursor demonstration, in the following sections of this proposed rule we evaluate the District's control analysis for the two most substantial source categories of ammonia, which together sum to more than 90% of the emissions in the SJV: CAFs and fertilizer application.

a. Summary of State's Submission

The District presents its analysis of ammonia controls for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The District evaluated its emission control measures for compliance with BACM for CAFs and described water-related measures applicable to fertilizer application that have co-benefits to air quality. The District presents its reasoning that measures that control VOC emissions, such as Rule 4570 for CAFs, also reduce ammonia emissions due to the physical processes occurring in decomposing manure and subsequent volatilization of decomposition products (like VOC and ammonia). As part of its process for identifying candidate BACM, considering the technical and economic feasibility of additional control measures, the District reviewed the EPA's guidance documents on BACM, and control measures implemented in other nonattainment areas in California and other states.[108]

For CAFs, the District discusses in detail how Rule 4570 (''Confined Animal Facilities'') is structured (*e.g.,* to address varying types of CAFs, including applicability thresholds); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; and the control menu requirements for each of those five operations.[109] The District summarizes the specific requirements applicable to each type of cattle-based CAF, including dairies, beef feedlots, and ''other cattle'' and describes its basis for ammonia emission reductions estimates, including cited research papers.

The District also compares Rule 4570 to other CAF rules imposed by the South Coast Air Quality Management District (AQMD), Bay Area AQMD, Sacramento Metropolitan AQMD, Imperial County Air Pollution Control District (APCD), and the State of Idaho.[110] The District evaluates a potential additional control measure—application of sodium bisulfate to reduce pH and bacterial levels in bedding for dairy cattle—and concludes that such measure is not feasible based on a number of factors, including health and safety of dairy workers and animals, impacts on water quality, and overall cost and effectiveness.[111]

For fertilizer application, as described in section II.A.3 of this proposed rule, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[112] Notwithstanding, the District describes how regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms [113] subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [114]

Overall, the District concludes that ''the Valley's ammonia emissions have been significantly reduced through stringent regulations, that additional ammonia control measures are infeasible, and that Valley sources are already implementing BACM.'' [115]

b. Summary of Adverse Comments

Public Justice states that ''[w]eaker controls are consistently allowed for agricultural sources,'' including an ''expansive menu of control options'' in Rule 4570, that they assert provide little to no emission reduction benefit.[116] More broadly, as described in section II.A.2 of this proposed rule, the commenters assert that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for also reducing PM concentrations,'' and cite several studies in support of this argument.[117] The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[118] The commenters

[104] 40 CFR 51.1010(a)(3)(i).

[105] 40 CFR 51.1010(a)(3)(ii).

[106] 40 CFR 51.1010(a)(3)(iii).

[107] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and the EPA's $PM_{2.5}$ Precursor TSD, 13.

[108] 2018 $PM_{2.5}$ Plan, Chapter 4, section 4.3.1.

[109] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[110] 2018 $PM_{2.5}$ Plan, App. C, C–323 to C–337.

[111] 2018 $PM_{2.5}$ Plan, App. C, C–338 to C–339.

[112] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[113] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[114] 2018 $PM_{2.5}$ Plan, App. C, C–341.

[115] 2018 $PM_{2.5}$ Plan, App C., C–312.

[116] Public Justice Comment Letter, 20.

[117] Public Justice Comment Letter, 16, Exhibits 31 through 34.

[118] Public Justice Comment Letter, 17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces

argue that the EPA ''should reject the plan's BACM analysis for failing to justify these weaker controls, and for being inconsistent with the Title VI prohibition against policies and practices that inflict disparate impacts.''

c. The EPA's Reconsidered Proposal

As a result of our proposed conclusion that ammonia remains a regulated precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the EPA has evaluated potential ammonia emissions control measures for the two most substantial source categories in the SJV and evaluated whether the State has implemented ammonia controls with a BACM/BACT level of stringency. Thus, the EPA has also evaluated the existing control measures that the State claims are BACM for two of the main sources of ammonia in the area, including confined animal facilities (CAFs) and fertilizer application.[119] As discussed below, we conclude that the SJV has not established that it has enforceable requirements in the SIP that meet a BACM level of stringency to reduce ammonia emissions from these two categories. Therefore, we propose to disapprove BACM for ammonia sources in the SJV.

Our basis for proposing to disapprove BACM for ammonia sources flows from the controls analysis we have reviewed and discuss in section II.A.3 of this proposed rule. We agree with the commenters that the analysis of potential controls in the 2018 $PM_{2.5}$ Plan was weak in two general areas: (1) incomplete quantification of existing ammonia emission reductions, and (2) lack of consideration of potential ammonia control measures identified in research studies. In that section we describe the Plan's weaknesses with respect to quantifying emission reductions and rely on that description for purposes of evaluating BACM.

Similarly, in section II.A.3, we discuss additional options for ammonia control that we will not reiterate here. Based on our review of the additional research studies cited by the commenters with respect to CAFs, measures such as those for adjusting the protein content of livestock feed (*e.g.,* reducing the portion of beef cattle finishing diets by 1.5% steam-flaked corn), manure handling and storage (*e.g.,* washing dairy cow collecting yards after each milking event, covering solid manure stores with sheeting), and land application of slurry (*e.g.,* injection application techniques), it appears that additional measures may be available to evaluate. Absent a thorough and more current evaluation of technological and economic feasibility of potential measures as applied in the SJV, we propose to find that the State has not demonstrated whether or how additional measures (*e.g.,* in the form of existing options that could also be feasibly implemented, or new options that may lead to increased reductions) may have been evaluated, implemented (even partially) by the existing rules, or set aside for reasons of technological feasibility or economic feasibility, consistent with the BACM requirements.

For fertilizer application, as discussed in section II.A.3 of this proposed rule, the District indicates that it does not have authority to regulate ammonia emissions from fertilizer application. Regardless of which State entity, as a matter of State law, has authority over this class of activities, CAA section 189(b)(1) requires that the State include provisions to ensure implementation of BACM for direct $PM_{2.5}$ and plan precursor emissions, and CAA section 110(a)(2)(E)(i) requires the State to provide necessary assurances that it has adequate authority to carry out the implementation plan for the area. While the Plan describes certain water-related measures (*e.g.,* Nutrient Management Plans and Nitrogen Management Plan) that subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to waste discharge requirements, and likely limit ammonia emissions to the air, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus suffer a similar problem as Rule 4570.[120]

We agree that as a general matter, managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the 2018 $PM_{2.5}$ Plan does not quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability. We propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling ammonia emissions from fertilizer application, the second largest source of such emissions in the SJV.

As a result of our proposal that the State has not demonstrated that BACM/BACT controls are in place for CAFs and fertilizer application, two source categories that make up more than 90% of the ammonia emissions in the SJV, we propose to disapprove the State's BACM demonstration for ammonia sources.

3. BACM for Building Heating Emission Sources

a. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV and presented our BACM evaluation for emission sources of direct $PM_{2.5}$ and $NO_X$.[121] We briefly summarize those components here with respect to the State's BACM demonstration for building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), in the SJV.

In Appendix C of the 2018 $PM_{2.5}$ Plan, the District identifies the stationary and area sources of direct $PM_{2.5}$ and $NO_X$ in the SJV that are subject to District emission control measures and provides its evaluation of these regulations for compliance with BACM requirements. As part of its process for identifying candidate BACM, the District reviewed the EPA's guidance documents on BACM, additional guidance documents on control measures for direct $PM_{2.5}$ and $NO_X$ emission sources, and control measures implemented in other ozone and $PM_{2.5}$ nonattainment areas in California and other states.[122] Based on these analyses, the District concludes that all best available control measures for stationary and area sources are in place in the SJV for $NO_X$ and directly emitted $PM_{2.5}$ for purposes of meeting the BACM/BACT requirement for the 2012 annual $PM_{2.5}$ NAAQS.

With respect to building heating emission sources, the District presents its evaluations of Rule 4902 (''Residential Water Heaters'') and Rule 4905 (''Natural Gas-Fired, Fan-Type Central Furnaces'') in sections C.20 and C.21, respectively, of Appendix C of the 2018 $PM_{2.5}$ Plan. Both rules are point of sale rules that limit what kinds of residential water heaters and furnaces may be sold in the SJV. The District describes the types of equipment covered by each rule, compares the specific provisions of each rule that

ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[119] By focusing on these two source categories, the EPA is not indicating that this is an exhaustive list of ammonia source categories that must be evaluated for BACM. However, because these two categories amount to more than 90% of the ammonia emissions in the SJV, we focus our analysis on these two categories.

[120] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[121] 86 FR 74310, 74324–74325.

[122] 2018 $PM_{2.5}$ Plan, Ch. 4, section 4.3.1.

limit $NO_X$ emissions [123] to comparable rules in other California air districts, and concludes that each rule represents BACM for their respective source category.

Rule 4902 applies to natural gas-fired, residential water heaters with heat input rates less than or equal to 75,000 British thermal units per hour (Btu/hr). The District tightened the rule's $NO_X$ limits in 2009; and the EPA approved the rule into the SIP in 2010.[124] The District estimates that, due to Rule 4902, annual average emissions of $NO_X$ would decrease from 2.15 tpd in 2013 to 1.91 tpd in 2025 (0.24 tpd decrease) and annual average emissions of direct $PM_{2.5}$ would increase from 0.21 tpd in 2013 to 0.23 tpd in 2025 (0.02 tpd increase).[125]

In addition to comparing the $NO_X$ limits in its Rule 4902 to rules in other California air districts, the District also presents a multi-factor comparison of natural gas-fired and propane-fired, water heaters to electric water heaters.[126] The District discussed the likely impacts of requiring electric water heaters, including the advantages such as no $NO_X$ emissions,[127] less expensive purchase price, and smaller size, and the disadvantages such as higher cost of electricity, and the costs of residence modifications to convert to electric. Based on 2017–2018 data, which is consistent with the timing of Plan adoption in 2018, the District calculated emission reductions and cost effectiveness of the three kinds of water heaters by fuel type and concluded that ''[w]hile the lifetime cost of an electric water heater is higher than that of propane and natural gas, the emissions benefits may make converting to electric water heating a viable control strategy.'' [128] The analysis does not explore the cost effectiveness of such controls and Rule 4902 does not include any requirements regarding electrification.

Rule 4905 applies to natural gas-fired, fan-type central furnaces with heat input rates less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr. In 2015, the District tightened the rule's $NO_X$ limits for residential units and expanded the rule to include commercial units and manufactured homes according to a phase-in schedule. The EPA approved the rule into the SIP in 2016.[129] The District estimates that, due to Rule 4905, annual average emissions for $NO_X$ will decrease from 2.44 tpd in 2013 to 2.13 tpd in 2025 (0.31 tpd decrease) and annual average emissions for direct $PM_{2.5}$ will increase from 0.20 tpd in 2013 to 0.22 tpd in 2025 (0.02 tpd increase).[130] Given the need to extend certain compliance deadlines in subsequent amendments to Rule 4905 due to limited supply of certified compliant units,[131] the District states that it had identified no additional emission reduction measures for this source category as of that point in time.[132]

As noted in the EPA's 2021 Proposed Rule, we provided our evaluation of the District's BACM demonstration for stationary and area sources in general, and several source categories in more detail, in three documents: (1) section III of the EPA's ''Technical Support Document, EPA Evaluation, San Joaquin Valley Serious Area Plan for the 2012 Annual $PM_{2.5}$ NAAQS,'' December 2021 (''EPA's 2012 Annual $PM_{2.5}$ TSD''); (2) the EPA's ''Technical Support Document, EPA Evaluation of BACM/MSM, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's BACM/MSM TSD''); and (3) the EPA's ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020 (''EPA's 2020 Response to Comments''). In particular, the EPA's 2020 Response to Comments presented our evaluation of the District's BACM demonstration for residential water heaters and residential and commercial, natural gas-fired, fan-type central furnaces.[133] At that time we found that the requirements for residential fuel combustion covered by Rule 4902 and Rule 4905 represented BACM.[134] In addition, the EPA concluded that setting a zero-$NO_X$ standard for heating appliances in new buildings reasonably requires additional consideration and analysis of technological and economic feasibility by the District because, per the 2018 $PM_{2.5}$ Plan, the most common types of residential water heaters and furnaces are those that use natural gas as fuel.

We also noted that the building codes referenced by commenters at that time appear to be green building code ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction.[135] Such ordinances, most of which appeared to have been adopted in late 2019 and early 2020, fell within a category known as ''reach codes,'' which are city and county building code standards for energy efficiency that exceed California's State-wide standards. We stated that California law requires local governments to submit proposed ordinances to the California Energy Commission (CEC) for a determination that they will be both cost effective and more energy efficient than statewide standards; compliance with this procedure is necessary for such measures to be enforceable.[136] We also noted that ordinances adopted by city councils and county officials are legally distinct from measures adopted by the governing boards of the respective air districts and that it did not appear at the time that California air districts had adopted similar restrictions.

b. Summary of Adverse Comments

Public Justice states that further emission controls are available for building heating via the electrification of furnaces, water heaters, and other gas-fired appliances.[137] The commenters refer to comments submitted by a group of environmental, public health, and community organizations (collectively referred to herein as ''NPCA'') on the EPA's proposed rule on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan,[138] noting that building electrification requirements to reduce emissions from such sources already

[123] The District notes that equipment subject to Rule 4902 are fired on natural gas that meets California Public Utility Commission standards and, therefore, emit only low amounts of $SO_X$ and direct $PM_{2.5}$. 2018 $PM_{2.5}$ Plan, App. C, C–288.

[124] 75 FR 24408 (May 5, 2010).

[125] 2018 $PM_{2.5}$ Plan, App. C, C–283.

[126] 2018 $PM_{2.5}$ Plan, App. C, C–288 to C–289.

[127] The EPA notes that while the $NO_X$ emissions of electric water heaters and furnaces are zero, there could be an increase in $NO_X$ emissions from electric power plants.

[128] 2018 $PM_{2.5}$ Plan, App. C, C–289.

[129] 81 FR 17390 (March 29, 2016).

[130] 2018 $PM_{2.5}$ Plan, App. C, C–290.

[131] The District further amended Rule 4902 in 2018, 2020, and 2021 to extend the compliance deadline for specific units due to limited supply of certified compliant units, with each amendment applying to a smaller subset of those specific units. See, *e.g.,* San Joaquin Valley UAPCD, ''Item Number 10: Adopt Proposed Amendments to Rule 4905 (Natural Gas-Fired, Fan-Type Central Furnaces),'' December 16, 2021, 2–3.

[132] 2018 $PM_{2.5}$ Plan, App. C, C–293. Unlike the District's consideration of electric water heaters, the District did not present an evaluation of electric furnaces in its analysis of Rule 4905.

[133] EPA's 2020 Response to Comments, Comment 6.O and Response 6.O, 142–148.

[134] EPA's 2020 Response to Comments, 146–147.

[135] EPA's 2020 Response to Comments, 147–148.

[136] California 2019 Building Energy Standards, at California Code of Regulations (CCR), Title 24, Part 1, Article 1, Sec. 10–106 (''Locally Adopted Energy Standards''); see also *https://ww2.energy.ca.gov/title24/2016standards/ordinances.*

[137] Public Justice Comment Letter, 19.

[138] Comment letter dated and received April 27, 2020, from Mark Rose, NPCA, et al., to Rory Mays, EPA, including Appendices A through G. The seven environmental and community organizations, in order of appearance in the letter, are the National Parks Conservation Association (NPCA), Earthjustice, Central Valley Air Quality Coalition, Coalition for Clean Air, Central Valley Environmental Justice Network, The Climate Center, and Central Valley Asthma Collaborative (collectively ''NPCA'').

exist in over 30 jurisdictions in California and other states. The commenters state that, since that time, additional jurisdictions have moved forward with gas bans, appliance standards, and other strategies for building heating.[139]

With respect to the EPA's response to the NPCA comments in 2020,[140] Public Justice argues that the ''EPA merely asserted that the District had found increased building electrification infeasible,'' despite the record showing that other jurisdictions required such measures, and assert that the District noted the potential of such measures but rejected them without explanation. The commenters further argue that the EPA did not rebut evidence on the benefits and feasibility of such measures, instead noting the need for further consideration, and that two years later, the Plan does not provide further consideration.

c. The EPA's Reconsidered Proposal

Based on the adverse comments from Public Justice, the EPA has reconsidered our proposed approval of the State's demonstration of BACM for $NO_X$ and direct $PM_{2.5}$ emissions from building heating appliances, such as residential water heating and residential and commercial space heating. As discussed below, we now propose to disapprove the State's BACM demonstration for such building heating emission sources.

Although the EPA has previously approved the State's BACM demonstration for building heating emission sources in 2020 with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan, and such approval was upheld by the Ninth Circuit Court of Appeals,[141] several factors have reshaped the facts and circumstances of controlling emissions from such sources as of 2022 and beyond. First, while building ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction were starting to appear in 2019 and 2020, as Public Justice correctly asserts, two additional years have passed and additional jurisdictions have adopted gas bans, appliance standards, and other strategies for building heating.[142] A recent policy brief published by the UCLA School of Law states that 52 cities and counties in California have adopted building codes to reduce their reliance on gas for building heating appliances, and discusses several examples.[143] The growth in the number and types of local control measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters support their general availability as technologically feasible measures.

Second, the time horizon of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan is one year later (2025 attainment date) than that of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the Plan (2024 attainment date), affording additional time for potential control measures to achieve emission reductions that may assist attainment of the 2012 annual $PM_{2.5}$ NAAQS. Even if full implementation of such new measures is not possible by the applicable attainment date, the State should evaluate whether they could be implemented in part, consistent with the fifth step for BACM/BACT evaluation discussed in the $PM_{2.5}$ SIP Requirements Rule and the General Preamble (*i.e.,* to determine the earliest date by which a control measure or technology can be implemented in whole or in part).[144]

Third, some of the underlying bases for the District's cost comparison for residential water heating may have changed since the District's 2018 adoption of the Plan. For example, in comparing emission reductions and cost effectiveness of low-$NO_X$ natural gas, propane, and electric water heaters, the District used data on energy factors and purchase price from Grainger Industrial Supply as of June 14, 2018, and lifetime energy cost data from the U.S. Energy Information Administration as of 2017. Furthermore, as claimed by Public Justice, the District did not explain its rejection of additional control measures of this type, other than to assert that they were generally more costly. Regarding residential and commercial space heating, CARB and the District did not provide a detailed economic feasibility analysis in the Plan. CARB and the District simply stated that, due to limited supply of certified compliant natural gas-fired units to comply with Rule 4905, they could identify no additional emission reduction measures. The incomplete cost analyses presented by the District, changes in costs over time, and lack of justification for rejecting measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters indicate an insufficient economic feasibility analysis.

Fourth, CARB and at least one other air district (Bay Area AQMD) are moving forward in developing measures to set zero-emission standards for space heaters and water heaters. In developing its 2022 State SIP Strategy (for the 2015 ozone NAAQS), CARB has stated that the ''fuels we use and burn in buildings, primarily natural gas, for space and water heating contribute significantly to building-related criteria pollutant and GHG emissions and provide an opportunity for substantial emissions reductions where zero-emission technology is available.'' [145] Accordingly, CARB is developing zero-emission standard concepts and, given the intersection of air quality needs and other areas of building and energy regulation, and identifying other regulatory entities that they plan to engage, including the U.S. Department of Energy, CEC, and the California Building Standards Commission, Department of Housing and Community Development. We note, however, that the proposed 2022 State SIP Strategy released August 12, 2022, anticipates implementation starting in 2030, pending rule development and CARB Board hearing in 2025.[146]

The Bay Area AQMD hosted public meetings in 2021 and developed draft amendments to certain rules that would reduce $NO_X$ emissions from residential and commercial furnaces and water heaters.[147] Specifically, Bay Area AQMD has developed draft amendments to two rules: (1) Regulation 9, Rule 4 (''Nitrogen Oxides from Fan Type Residential Central Furnaces''), which applies to furnaces with a heat input rate of less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr (like SJVUAPCD Rule 4905); and (2) Regulation 9, Rule 6 (''Nitrogen Oxides Emissions from

[139] Public Justice Comment Letter, 19, and Exhibits 41 through 44. Commenters also state that studies suggest these measures may provide particularly notable benefits to winter $PM_{2.5}$ peaks in the SJV. Id. at 19.

[140] EPA, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020. See Comment 6.O and Response 6.O on pages 142–147.

[141] Ninth Circuit Memorandum Order, 9. Regarding increased building electrification requirements, the Court stated that ''the EPA considered such an approach and reasonably accepted the State's determination that it was not feasible at this time.''

[142] See Public Justice Comment Letter, Exhibits 41 through 44.

[143] Heather Dadashi, Cara Horowitz, and Julia Stein, ''Pritzker Environmental Law and Policy Briefs, How Air Districts Can End $NO_X$ Pollution From Household Appliances,'' Emmett Institute on Climate Change and the Environment, UCLA School of Law, March 2022, 8.

[144] 81 FR 58010, 58083–58085.

[145] CARB, ''Draft 2022 State Strategy for the State Implementation Plan,'' January 31, 2022, 86–88.

[146] CARB, ''Proposed 2022 State Strategy for the State Implementation Plan,'' August 12, 2022, 101–103.

[147] A summary of the Bay Area AQMD's rule development is available at: *https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances.*

Natural Gas-Fired Boilers and Water Heaters''), which applies to water heaters with a rated heat input capacity of 75,000 Btu/hr or less (like SJVUAPCD Rule 4902), as well as additional source types and sizes.[148]

For Rule 4, Bay Area AQMD staff have developed draft amendments to lower the current $NO_X$ emission limit for applicable furnaces from 40 nanograms of $NO_X$ per joule of useful heat (ng/j) to 14 ng/j (which would match the limit in SJVUAPCD Rule 4905) in the short term (with a compliance date of January 1, 2023); followed by a zero-$NO_X$ emission requirement (with a compliance date of January 1, 2029); and expand the applicability beyond fan-type central furnaces to other types of equipment (*e.g.,* wall furnaces and direct vent units).[149] For Rule 6, which contains $NO_X$ limits for small boilers and water heaters, Bay Area AQMD staff proposes a zero-$NO_X$ emission requirement. However, staff also note that while technologies achieving zero-$NO_X$ emissions exist, ''they are limited in availability and can be expensive,'' that such standards would be ''technology and market-forcing,'' and, therefore, staff proposes compliance dates of January 1, 2027, and January 1, 2031, depending on equipment heat rate (*i.e.,* the size of the boiler or water heater).[150]

CARB and Bay Area AQMD efforts in this area underscore the importance of building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), throughout California and the continued effort to implement available control measures for these sources for criteria pollutant attainment planning requirements. At the same time, while SJVUAPCD, CARB, and Bay Area AQMD each acknowledge that zero-$NO_X$ emission technology for small residential and commercial space and water heating is available, it is unclear what a feasible implementation horizon might be in light of CARB's strategy and the Bay Area AQMD's draft amendments. The plan as submitted did not address how such implementation considerations may or may not affect the feasibility of setting such zero-$NO_X$ emission standards for space and water heating in small residential and commercial buildings in the SJV.

Given the factors discussed above, we now propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling $NO_X$ and direct $PM_{2.5}$ emissions from building emission heating sources in the SJV.

*C. Attainment Demonstration*

1. Summary of 2021 Proposed Rule

In sections IV.C (air quality modeling) and IV.F (attainment demonstration) of our 2021 Proposed Rule, the EPA summarized the CAA and regulatory requirements for air quality modeling and attainment demonstrations, the State's submission in the SJV $PM_{2.5}$ Plan, and our evaluation thereof.[151] We briefly summarize those components herein.

Sections 188(c)(2) and 189(b)(1)(A) of the CAA require that Serious area plans must include a demonstration (including air quality modeling) that provides for attainment of the $PM_{2.5}$ NAAQS as expeditiously as practicable, but no later than the end of the tenth calendar year after the area's designation as nonattainment. The $PM_{2.5}$ SIP Requirements Rule also specifies that the control strategy in a Serious area attainment plan must provide for attainment as expeditiously as practicable.[152] The outermost statutory Serious area attainment date for the 2012 annual $PM_{2.5}$ NAAQS in the SJV is December 31, 2025 (absent an EPA-approved attainment date extension request under CAA section 188(e)). For purposes of determining the attainment date that is as expeditious as practicable, the State must conduct future year modeling that takes into account emissions growth, known emissions controls (including any controls that were previously determined to be RACM/RACT or BACM/BACT), any other emissions controls required to meet BACM/BACT, and additional measures as needed for expeditious attainment of the NAAQS. The regulatory requirements for Serious area plans are codified at 40 CFR 51.1010 (control strategy requirements) and 40 CFR 51.1011(b) (attainment demonstration and modeling requirements). We also described the EPA's $PM_{2.5}$ modeling guidance (''Modeling Guidance''),[153] including our recommendations therein for photochemical modeling, inputs, procedures, performance evaluation, emissions simulation, and calculating relative response factors (RRFs).

With respect to air quality modeling, the 2018 $PM_{2.5}$ Plan included the State's modeled attainment demonstration projecting that the SJV will attain the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025; the State's primary discussion of the photochemical modeling appears in Appendix K (''Modeling Attainment Demonstration''). The State provides a conceptual model of $PM_{2.5}$ formation in the SJV as part of the modeling protocol in Appendix L (''Modeling Protocol'') and describes emission input preparation procedures. The State presents additional relevant information in Appendix C (''Weight of Evidence Analysis'') of CARB's staff report for the 2018 $PM_{2.5}$ Plan,[154] which includes ambient trends and other data in support of the demonstration of attainment by 2025.

In the 2021 Proposed Rule, the EPA presented its review of the State's modeling approach and its many interconnected facets, including model input preparation, model performance evaluation, use of the model output for the numerical NAAQS attainment test, and modeling documentation, and found it to be generally consistent with the EPA's recommendations in the Modeling Guidance. We incorporated our evaluation of the Plan's modeling for the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan[155] and extended that evaluation with information specific to the 2012 annual $PM_{2.5}$ NAAQS. Overall, in the 2021 Proposed Rule, we considered the State's analyses consistent with the EPA's guidance on modeling for $PM_{2.5}$ attainment planning purposes and proposed to find that the modeling in the 2018 $PM_{2.5}$ Plan was adequate for the purposes of supporting the State's RFP demonstration and the attainment demonstration.

With respect to the attainment demonstration, the SJV $PM_{2.5}$ Plan includes a modeled demonstration projecting attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, based on emission reductions

[148] As in the San Joaquin Valley, larger boilers and similar equipment used in industrial, institutional, and large commercial settings are subject to other rules of the Bay Area AQMD, and therefore not subject to Rule 4 or Rule 6.

[149] Bay Area AQMD, ''Workshop Report, Draft Amendments to Building Appliance Rules—Regulation 9, Rule 4: Nitrogen Oxides from Fan Type Residential Central Furnaces and Rule 6: Nitrogen Oxide Emissions from Natural Gas-Fired Boilers and Water Heaters,'' September 2021, 1.

[150] Id.

[151] 86 FR 74310, 74322–74324 (air quality modeling) and 74325–74338 (attainment demonstration).

[152] 40 CFR 51.1011(b)(1); 81 FR 58010, 58087.

[153] Memorandum dated November 29, 2018, from Richard Wayland, Air Quality Assessment Division, OAQPS, EPA, to Regional Air Division Directors, EPA, Subject: ''Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze,'' (''Modeling Guidance'').

[154] CARB, ''Staff Report, Review of the San Joaquin Valley 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' release date December 21, 2018 (''CARB Staff Report'').

[155] EPA Region IX, ''Technical Support Document, EPA Evaluation of Air Quality Modeling, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's 2006 NAAQS Modeling TSD'').

from implementation of baseline control measures and the development, adoption, and implementation of additional control measures to meet specific enforceable commitments. In the EPA's 2021 Proposed Rule, we described how the Plan's control strategy was to reduce emissions from sources of $NO_X$ and direct $PM_{2.5}$ and that most of the projected emission reductions are achieved by baseline measures—*i.e.,* the combination of State and District measures adopted prior to the State's and District's adoption of the Plan—that will achieve ongoing emission reductions from the 2013 base year to the 2025 projected attainment year.

The remainder of the Plan's emission reductions are to be achieved by additional measures to meet enforceable commitments, including potential regulatory and incentive-based measures and, as necessary, substitute measures.[156] In the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, CARB and the District, respectively, included commitments to take action on specific measures by specific years or to develop substitute measures (referred to as ''control measure commitments'') and to achieve specified amounts of $NO_X$ and direct $PM_{2.5}$ emission reductions by certain dates (referred to as ''aggregate tonnage commitments'').[157] We refer to these complementary commitments herein as ''aggregate commitments.''

In the 2021 Proposed Rule, the EPA described several findings relating to our evaluation of the SJV $PM_{2.5}$ Plan's attainment demonstration. First, we proposed to approve the Plan's emissions inventories and to find the Plan's air quality modeling adequate.[158] Second, we proposed to find that the Plan provides for expeditious attainment through the timely implementation of the control strategy to reduce emissions from sources of $NO_X$ and direct $PM_{2.5}$, including RACM, BACM, and any other emission controls necessary for expeditious attainment.

Third, the EPA proposed to find that the emissions reductions that are relied on for attainment in the SIP submission are creditable. We noted that the SJV $PM_{2.5}$ Plan relies principally on already adopted and approved rules to achieve the emissions reductions needed to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and that the balance of the reductions that the State has modeled to achieve attainment by this date is currently represented by enforceable commitments that account for 13.8% of the $NO_X$ and 8.0% of the direct $PM_{2.5}$ emissions reductions needed for attainment. In terms of our evaluation of CARB and the District's enforceable commitments, we proposed to find that circumstances in the SJV for the 2012 annual $PM_{2.5}$ NAAQS warrant the consideration of enforceable commitments and that the EPA's three criteria for such commitments had been met: (1) the commitments constitute a limited portion of the required emissions reductions; (2) both CARB and the District have demonstrated their capability to meet their commitments; and (3) the commitments are for an appropriate timeframe. We therefore proposed to approve the State's reliance on these enforceable commitments in its attainment demonstration.

Overall, in the 2021 Proposed Rule, we proposed to approve the SJV $PM_{2.5}$ Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025, consistent with the requirements of CAA section 189(b)(1)(A). We presented the basis for our proposed determination in sections IV.F.3.a through IV.F.3.e of the 2021 Proposed Rule and provided further detail of our evaluation of baseline measures and the additional measures and aggregate commitments in sections II and IV, respectively, of the EPA's 2012 Annual $PM_{2.5}$ TSD.

2. Summary of Ninth Circuit Order and Adverse Comments

As introduced in section I.D of this proposed rule, in response to a petition for review of the EPA's approval of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, the Ninth Circuit Court of Appeals issued a Memorandum Opinion that, in part, vacated the final action with respect the EPA's second factor for evaluating the validity of the State's enforceable commitments (*i.e.,* whether the State is capable of fulfilling its commitment). The Ninth Circuit's order is very relevant to this proposed rule because the State relied on the same common control strategy, including the same set of enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan.

The Ninth Circuit found that the EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total $NO_X$ reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [159] In response to the EPA's arguments that: (1) the funding shortfall may be smaller than projected; (2) emission reductions may be less expensive than the strategy predicts; (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls; and (4) California and the District may identify other measures to fulfill their commitments, the Court wrote that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [160] It is important to emphasize that the State relied heavily on the projected emission reductions that it hopes to achieve through new control measures and emissions reductions reflected in the aggregate commitments. These reductions are crucial to the State meeting the modeled attainment demonstration and RFP requirements. If it is not credible that the State can meet the commitments, then the EPA cannot approve other nonattainment plan elements that rely upon them.

Separately, in comments on the EPA's 2021 Proposed Rule, Public Justice states that CARB and the District's aggregate tonnage commitments are to ''achieve a specific amount of reductions at the last possible moment prior to the attainment deadline with no concrete strategies for how that will be achieved.'' [161] They assert that prior plans with aggregate tonnage commitments for the 1997 annual $PM_{2.5}$ NAAQS by 2015 (*i.e.,* the 2008 $PM_{2.5}$ Plan) and then by 2020 (*i.e.,* the SJV $PM_{2.5}$ Plan) failed to attain those standards and that such past failures implies that the commitments failed to

[156] In this proposed rule, the term ''substitute measures'' means additional control measures that were not identified in CARB and the District's original control measure commitments in adopting the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, respectively. The ''substitute'' aspect primarily relates to emission reductions (*i.e.,* providing emission reductions where any adopted measure achieves less emission reductions than originally estimated, and/or providing emission reductions in lieu of any originally planned measure that is not adopted). They are also sometimes referred to as ''alternative measures'' in the SJV $PM_{2.5}$ Plan and adopting resolutions.

[157] CARB Resolution 18–49 and SJVUAPCD Governing Board Resolution 18–11–16, paragraph 6.

[158] Sections IV.A (emissions inventory) and IV.C (air quality modeling) of the 2021 Proposed Rule.

[159] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022), 6.

[160] Id. at 7.

[161] Public Justice Comment Letter, 20.

deliver the promised clean air.[162] The commenters further state that ''deferred, unspecified, and last-minute promises to achieve reductions (*i.e.,* aggregate commitments), inflicts disparate impacts in violation of Title VI,'' irrespective of whether the commitments comply with the CAA.

3. The EPA's Reconsidered Proposal

As a result of the Ninth Circuit Memorandum Opinion with respect to the SJV $PM_{2.5}$ Plan's enforceable commitments, the EPA has reconsidered its proposed approval of the Plan's demonstration of attainment for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and now proposes to disapprove the Plan's attainment demonstration. The Ninth Circuit Memorandum Opinion raised concerns about the ability of CARB and the District to fulfill the commitments.

We present our reconsideration in the following sections of this proposed rule: (1) our reconsideration of CARB and the District's enforceable commitments and proposal that the commitments do not meet the second factor of the EPA's three-factor test (in section II.C.3.a); and (2) the effect of our proposed disapproval of the State's enforceable commitments and specific portions of the State's BACM demonstration on the modeled attainment demonstration (in section II.C.3.b).

a. Additional Measures and Enforceable Commitments

In this subsection we re-examine CARB and the District's enforceable commitments. We describe CARB and the District's progress in adopting specific measures that they committed to present for governing board adoption, and evaluate whether CARB and the District have demonstrated the capability to achieve specific tonnages of reductions that they committed to achieve by the 2025 attainment year. We first enumerate the measures that have already been approved into the SIP and quantify the amount of the tonnage commitment that these account for. We then calculate CARB and the District's remaining commitments as of the time of this notice, describe the strategy that CARB and the District have provided for achieving the remaining reductions (consisting of submitted measures that have not yet been approved into the SIP, adopted measures that have not yet been submitted to the EPA, measures under development, and other potential future measures), and calculate the reductions that may be associated with these measures. We conclude that although CARB and the District have made substantial progress toward achieving the committed-to reductions, CARB and the District have not presented a plausible strategy demonstrating that they are capable of achieving the *entirety* of the aggregate commitment.

In our 2021 Proposed Rule, the EPA described the SJV $PM_{2.5}$ Plan's series of CARB and District commitments to achieve emission reductions through additional control measures, beyond baseline measures, that are intended to contribute to expeditious attainment of the 2012 annual $PM_{2.5}$ NAAQS. For mobile sources, CARB identified a list of 12 State regulatory measures and 3 incentive-based measures that CARB has committed to propose to its Board for consideration by specific years.[163] For stationary sources, the District identified a list of nine regulatory measures and three incentive-based measures that the District has committed to propose to its Board for consideration by specific years.[164]

The Plan contains CARB's and the District's estimates of the emission reductions that could be achieved by each of these additional measures, if adopted as planned.[165] As we described in our 2021 Proposed Rule, CARB's commitments are contained in CARB Resolution 18–49 (October 25, 2018) and the Valley State SIP Strategy and consist of two parts: a control measure commitment and a tonnage commitment.

First, CARB has committed to ''begin the measure's public process and bring to the Board for consideration the list of proposed SIP measures outlined in the *Valley State SIP Strategy* and included in Attachment A, according to the schedule set forth.'' [166] By email dated November 12, 2019, CARB confirmed that it intended to begin the public process on each measure by discussing the proposed regulation or program at a public meeting (workshop, working group, or Board hearing) or in a publicly-released document, and to then propose the regulation or program to its Board.[167] Second, CARB has committed ''to achieve the aggregate emissions reductions outlined in the Valley State SIP Strategy of 32 tpd of $NO_X$ and 0.9 tpd of $PM_{2.5}$ emissions reductions in the San Joaquin Valley by 2024 and 2025.'' [168] The Valley State SIP Strategy explains that CARB's overall commitment is to ''achieve the total emission reductions necessary to attain the Federal air quality standards, reflecting the combined reductions from the existing control strategy and new measures'' and that ''if a particular measure does not get its expected emissions reductions, the State is still committed to achieving the total aggregate emission reductions.'' [169]

Similarly, in our 2021 Proposed Rule, we explained that the District's commitments are contained in SJVUAPCD Governing Board Resolution 18–11–16 (November 15, 2018) and Chapter 4 of the 2018 $PM_{2.5}$ Plan and also consist of two parts: a control measure commitment and a tonnage commitment. First, the District has committed to ''take action on the rules and measures committed to in Chapter 4 of the Plan by the dates specified therein, and to submit these rules and measures, as appropriate, to CARB within 30 days of adoption for transmittal to EPA as a revision to the [SIP].'' [170] By email dated November 12, 2019, the District confirmed that it intended to take action on the listed rules and measures by beginning the public process on each measure, *i.e.,* discussing the proposed regulation or program at a public meeting, including a workshop, working group, or Board hearing, or in a publicly-released document, and then proposing the rule or measure to the SJVUAPCD Governing Board.[171] Second, the District has

[162] Public Justice refers specifically to the EPA's November 2016 finding of failure to attain and the EPA's November 2021 final disapproval of the 1997 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan. 81 FR 84481 (November 23, 2016) and 86 FR 67329 (November 26, 2021), respectively.

[163] CARB Resolution 18–49, Attachment A and Valley State SIP Strategy, Table 7 (''State Measures and Schedule for the San Joaquin Valley''). The schedule of proposed SIP measures in Table 7 includes two additional CARB measures: the second phase of the Advanced Clean Cars Program (''ACC 2'') and the ''Cleaner In-Use Agricultural Equipment'' measures. However, these measures are not scheduled for implementation until 2026 and 2030, respectively, which is after the January 1, 2025 implementation deadline under 40 CFR 51.1011(b)(5) for control measures necessary for attainment by December 31, 2025. Therefore, we are not reviewing these measures as part of the control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

[164] SJVUAPCD Governing Board Resolution 18–11–16 and 2018 $PM_{2.5}$ Plan, Table 4–4 (''Proposed Regulatory Measures'') and Table 4–5 (''Proposed Incentive-Based Measures'').

[165] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'') and Valley State SIP Strategy, Table 8 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[166] CARB Resolution 18–49, 5.

[167] Email dated November 12, 2019, from Sylvia Vanderspek, CARB, to Anita Lee, EPA Region IX, ''RE: SJV $PM_{2.5}$ information'' (attaching ''Valley State SIP Strategy Progress'') and CARB Staff Report, 14.

[168] CARB Resolution 18–49, 5.

[169] Valley State SIP Strategy, 7.

[170] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[171] Email dated November 12, 2019, from Jon Klassen, SJVUAPCD, to Wienke Tax, EPA Region IX, ''RE: follow up on aggregate commitments in SJV $PM_{2.5}$ Plan'' (attaching ''District Progress in

committed to ''achieve the aggregate emissions reductions of 1.88 tpd of $NO_X$ and 1.3 tpd of $PM_{2.5}$ by 2024/2025'' through adoption and implementation of these measures or, if the total emission reductions from these rules or measures are less than these amounts, ''to adopt, submit, and implement substitute rules and measures that achieve equivalent reductions in emissions of direct $PM_{2.5}$ or $PM_{2.5}$ precursors'' in the same implementation timeframes.[172]

In sections IV.F.3.c and IV.F.3.d of our 2021 Proposed Rule, the EPA described CARB's and the District's progress as of that point in time on their control measure commitments and progress towards fulfilling their respective aggregate commitments, respectively. Based on our reconsideration of the State's enforceable commitments in light of the Ninth Circuit Memorandum Opinion, while we propose to retain certain findings with respect to the State's progress, we now propose that the State has not adequately demonstrated that it can fulfill the remaining portions of its enforceable commitments (*i.e.,* the second factor of the EPA's three-factor test). We present our reconsidered evaluation of the status of CARB's and the District's control strategy and our three-factor test for enforceable commitments, as follows.

With respect to progress on the control measure commitments, CARB and the District together have adopted 18 measures of the 27 control measure commitments in the SJV $PM_{2.5}$ Plan and have begun the public process on 5 of the remaining control measure commitments, which is unchanged since the time of our 2021 Proposed Rule. This progress is described in further detail in CARB and the District's ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley'' (2021 Progress Report).[173] For CARB's portion, CARB has adopted 10 of the 15 measures identified in its commitment (including one incentive-based measure) and begun the public process on 3 of the remaining 5 measures. For the District's portion of the control measure commitments, the District has adopted 8 of the 12 measures identified in its commitment (including one incentive-based measure) and begun the public process on 2 of the remaining 4 measures.

Although CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments, they have not yet fulfilled the commitments for several measures in accordance with the timeframes established in the SJV $PM_{2.5}$ Plan. We provide further detail on CARB and the District's control measure commitments in section IV.A of the EPA's 2012 Annual $PM_{2.5}$ TSD (including tables IV–A and IV–B regarding CARB and the District's control measure commitments, respectively).[174]

Regarding the remaining nine measures not yet proposed for board consideration, we continue to note that one measure, Rule 4550 (''Conservation Management Practices''), has an action year of 2022 in the 2018 $PM_{2.5}$ Plan (*i.e.,* the District has the remainder of 2022 to present a proposed measure for board consideration) and that four regulatory measures and four incentive-based measures are overdue. For the four regulatory measures, while CARB and the District have not proposed these measures to their respective boards, they began the public process on each of the four measures on time with respect to the schedule of their respective public process commitments. To our knowledge, CARB anticipates board consideration of the diesel fuel measures in 2022 and the forklift measure in 2022 or 2023[175] and continues to develop the airport ground support equipment measure; the District continues to evaluate potential amendments to Rule 4692 in the near future.[176]

For the four incentive-based measures, CARB and the District continue to invest in reducing emissions from heavy-duty trucks and buses, off-road equipment, agricultural operation internal combustion engines, and commercial under-fired charbroiling.[177] However, while CARB and the District have discussed the proposed programs at board hearings,[178] to our knowledge, CARB and the District have not started the public process for the four incentive-based control measure commitments as enforceable measures to be submitted to the EPA for approval and inclusion as control measures in the California SIP. Furthermore, as discussed in section IV.F.3.c of our 2021 Proposed Rule, for heavy-duty trucks and off-road equipment, CARB acknowledges that many of the project lives do not span the attainment year[179] and, thus, while these projects may accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration.

Overall, while CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments that were submitted in the SJV $PM_{2.5}$ Plan, in light of the Ninth Circuit Memorandum Opinion, we have reconsidered the effect of the eight overdue measures of the original commitments and in particular the overdue incentive-based measures, on our evaluation of CARB and the District's aggregate tonnage commitments and our three-factor test. Under the second factor of the EPA's test for enforceable commitments, the

Implementing Commitments with 2018 $PM_{2.5}$ Plan'').

[172] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[173] ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley,'' October 19, 2021. Transmitted to the EPA by letter dated October 20, 2021, from Richard W. Corey, Executive Officer, CARB, to Deborah Jordan, Acting Regional Administrator, EPA Region IX. See sections of 2021 Progress Report entitled ''Progress in Implementing District Measures'' and ''Progress in Implementing CARB Measures.''

[174] We note that Table IV–A of the EPA's 2012 Annual $PM_{2.5}$ TSD contained an error with respect to the adoption date of CARB's measure for Transportation Refrigeration Units Used for Cold Storage. While CARB had heard proposed amendments to the measure on September 23, 2021, the measure was not actually adopted until February 24, 2022, following further process and rule adjustments required by the Board. CARB Resolution 22–5, February 24, 2022.

[175] In the 2021 Progress Report (dated October 19, 2021), page 20, CARB indicates that the Zero-Emission Off-Road Forklift Regulation Phase 1 would be presented for Board consideration ''as early as 2022,'' while CARB's updated ''SJV $PM_{2.5}$ SIP Measure Tracking'' (dated December 2021) anticipates presenting the measure to the Board in Summer 2023.

[176] 2021 Progress Report, 8–9, 20–22, and tables 2 and 3.

[177] CARB, ''Long-Term Heavy-Duty Investment Strategy, Including Fiscal Year 2020–21 Three-Year Recommendations for Low Carbon Transportation Investments,'' (App. D to CARB's ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives''), release date October 8, 2021; and SJVUAPCD, ''Comprehensive Annual Financial Report, Fiscal Year Ended June 30, 2020,'' release date December 23, 2020. See also, 2021 Progress Report, 3 and 15.

[178] For example, CARB staff discussed the Accelerated Turnover of Trucks and Buses Incentive Measure at its annual 2020 update to the CARB Board. CARB presentation, ''Update on the 2018 $PM_{2.5}$ SIP for the San Joaquin Valley,'' October 22, 2020. District staff discussed and adopted an emission reductions strategy for commercial under-fired charbroiling, including incentives, in December 2020. SJVUAPCD, ''Item Number 11: Adopt Proposed Commercial Under-Fired Charbroiling Emission Reduction Strategy,'' December 17, 2020.

[179] Id. at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX, ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

Agency must evaluate whether a State is capable of fulfilling such commitments. The tardiness of presenting these control measures for board consideration renders the reductions from these measures more speculative under the second factor.

With respect to the aggregate tonnage commitments to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV, we reiterate that CARB committed to achieve 32 tpd of $NO_X$ and 0.9 tpd of $PM_{2.5}$ emissions reductions, and the District committed to achieve 1.88 tpd of $NO_X$ and 1.3 tpd of $PM_{2.5}$ emissions reductions by 2025. These aggregate tonnage commitments sum to 33.88 tpd $NO_X$ and 2.2 tpd direct $PM_{2.5}$. CARB and the District have committed to achieve these reductions via the 27 control measure commitments, or such other substitute measures as may be necessary, to achieve the aggregate tonnage commitments for $NO_X$ and direct $PM_{2.5}$.

For the purpose of our analysis of the State's progress toward achieving its aggregate tonnage commitments, of the 18 measures adopted by December 2021, as well as the adoption of an important substitute measure (the Agricultural Burning Phase-out Measure [180]), the State has submitted 12 measures as revisions to the California SIP (*i.e.,* more than the 9 measures submitted to EPA as of the time of the 2021 Proposed Rule). Since December 2021, the EPA finalized or proposed approval of three control measure SIP submissions that were control measure commitments in the SJV $PM_{2.5}$ Plan.

First, the EPA finalized approval of the Heavy-Duty Vehicle Inspection Program (HDVIP) and Periodic Smoke Inspection Program (PSIP).[181] However, as in our 2021 Proposed Rule, CARB has not yet provided its analysis of the basis for this emission reduction estimate (of 0.02 tpd direct $PM_{2.5}$, per the State's 2021 Progress Report). Therefore, the EPA is not proposing at this time to credit this measure with any particular amount of emission reductions towards attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Second, the EPA finalized approval of the Agricultural Burning Phase-out Measure,[182] which includes a schedule to phase-out (*i.e.,* introduce prohibitions of) agricultural burning for additional crop categories or materials accounting for a vast majority of the tonnage of agricultural waste in phases that started January 1, 2022, and become fully implemented by January 1, 2025.[183] The EPA received comments from the District that supported approval of the Agricultural Burning Phase-out Measure into the SIP while also advocating for a higher rule effectiveness rate (*i.e.,* 95% instead of EPA's proposed 80%),[184] which in turn would increase the amount of emission reductions that the EPA would credit towards fulfilling the District's aggregate tonnage commitment. We continue to evaluate these comments and for now have retained our proposal to credit the measure for emission reductions of 0.83 tpd $NO_X$ and 1.23 tpd direct $PM_{2.5}$, consistent with the 80% rule effectiveness rate used by the EPA in the 2021 Proposed Rule.

Third, the EPA has proposed approval of Rule 4311 (''Flares''), as amended December 17, 2020.[185] The District's staff report for Rule 4311 estimates that the emission reductions from these amendments would be 0.19 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$ in 2025.[186] The EPA continues to evaluate the District's estimate with respect to SIP-creditable emission reductions, though we note that they are relatively small when compared to the overall 207.38 tpd $NO_X$ and 6.4 tpd direct $PM_{2.5}$ modeled to attain the 2012 $PM_{2.5}$ NAAQS and to the combined aggregate tonnage commitments of 33.88 tpd $NO_X$ and 2.2 tpd direct $PM_{2.5}$.

Similar to our 2021 Proposed Rule, we propose to credit reductions from three measures, all of which are now approved into the SIP and have large associated emission reductions of direct $PM_{2.5}$ and/or $NO_X$ in the SJV.[187] The three measures are: Rule 4901 (''Wood Burning Fireplaces and Wood Burning Heaters''); two of three parts of the Agricultural Equipment Incentive Measure (for which we described our proposed SIP credit in the 2021 Proposed Rule); and the Agricultural Burning Phase-out Measure (for which we described our proposed SIP credit in this proposed rule).[188]

Based on these SIP-approved measures, our estimate of the remaining aggregate tonnage commitments remains the same as in our 2021 Proposed Rule. Specifically, in Table 1 herein we summarize the total $NO_X$ and direct $PM_{2.5}$ emission reductions that the State models as sufficient to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, the emission reductions attributed to baseline measures and new control strategy measures (including only measures currently approved into the California SIP), and the emission reductions remaining as aggregate tonnage commitments.

TABLE 1—REDUCTIONS FOR ATTAINMENT IN 2025 AND AGGREGATE TONNAGE COMMITMENTS

| | | $NO_X$ (tpd) | Direct $PM_{2.5}$ (tpd) |
|---|---|---|---|
| A | Total reductions from baseline and control strategy measures modeled to achieve attainment | 207.38 | 6.4 |
| B | Reductions from baseline measures | 173.5 | 4.2 |
| C | Reductions from additional measures *approved* into the California SIP | 5.29 | 1.69 |
| D | Total reductions remaining as commitments (A–B–C) | 28.59 | 0.51 |
| E | Percent of total reductions needed remaining as commitments (D/A) | 13.8% | 8.0% |

**Sources:** 2018 $PM_{2.5}$ Plan, Ch. 4, tables 4–3 and 4–7, and Appendix B, tables B–1 and B–2.

[180] See 87 FR 36222 (June 16, 2022).

[181] 87 FR 27949 (May 10, 2022).

[182] 87 FR 36222.

[183] SJVUAPCD, ''Supplemental Report and Recommendations on Agricultural Burning,'' June 17, 2021 (''2021 Supplemental Report''), including Table 2–1 (''Accelerated Reductions by Crop Category'').

[184] Letter dated January 25, 2022, from Jonathan Klassen, Director of Air Quality Science and Planning, SJVUPACD, to Michael Regan, Administrator, U.S. EPA.

[185] 87 FR 3736 (January 25, 2022).

[186] SJVUAPCD, ''Item Number 12: Adopt Proposed Amendments to Rule 4311 (Flares),'' December 17, 2020, Attachment C (''Final Draft Staff Report with Appendices for Proposed Amendments to Rule 4311''), 21–22.

[187] The seven additional measures submitted as SIP revisions for which the EPA has not proposed action as of August 2022 include: the Innovative Clean Transit measure (submitted February 13, 2020); Rules 4306 and 4320 (submitted March 12, 2021); Rule 4702 (submitted October 15, 2021); Rules 4352 and 4354 (submitted March 9, 2022), and the Residential Wood Burning Incentive Measure (submitted March 17, 2022).

[188] Final actions on these measures are as follows: 85 FR 44206 (July 22, 2020) (Rule 4901), 86 FR 73106 (December 27, 2021) (Agricultural Equipment Incentive Measure), and 87 FR 36222 (June 16, 2022) (Agricultural Burning Phase-out Measure).

As shown in Table 1, 13.8% of the $NO_X$ reductions necessary for attainment and 8.0% of the direct $PM_{2.5}$ reductions necessary for attainment remain as aggregate tonnage commitments (*i.e.,* combining CARB and the District's remaining commitments).[189] Based on the direct $PM_{2.5}$ emission reductions that the EPA has credited to Rule 4901 (0.2 tpd) and the Agricultural Burning Phase-out Measure (1.23 tpd), which add up to 1.43 tpd, we conclude that the District has exceeded its 1.3 tpd direct $PM_{2.5}$ commitment by 0.13 tpd.

Beyond the measures that the EPA has taken final action to approve into the California SIP and proposed to credit herein, CARB has provided updated emission reduction estimates for 10 additional measures, including 9 that have been adopted, as well as one substitute measure in development, as described in the 2021 Progress Report. The CARB measure with the largest updated emission reduction estimates is the Heavy-Duty Vehicle Inspection and Maintenance Program (''Heavy-Duty I/M'').

The District has similarly provided updated emission reduction estimates for seven additional measures, including six that have been adopted. The District measures with the largest updated emission reduction estimates include amendments to Rule 4702 (''Internal Combustion Engines'') (0.61 tpd $NO_X$), the Residential Wood Burning Devices Incentive Projects measure (0.33 tpd direct $PM_{2.5}$), and Rule 4354 (''Glass Melting Furnaces'') (0.5 tpd $NO_X$ and 0.04 tpd direct $PM_{2.5}$), as well as amendments planned in 2022 to Rule 4550 (''Conservation Management Practices'') (0.32 tpd direct $PM_{2.5}$).

The EPA is not proposing to credit towards the aggregate tonnage commitments the updated emission reduction estimates from these additional District measures. We will review and act on the CARB and District measures submitted to date (Innovative Clean Transit, Rule 4306, Rule 4320, Rule 4702, Rule 4352, Rule 4354, and the Residential Wood Burning Incentive Measure), as well as future measure submissions, in separate rulemakings, during which time the public will have an opportunity to review and provide comment.

Although we are not proposing to credit reductions from these measures at this time, in order to determine whether CARB and District have the capability to meet their aggregate tonnage commitments, we have re-evaluated the updated emission reduction estimates to assess whether they could meet the $NO_X$ and/or direct $PM_{2.5}$ emission reduction commitments with these measures or, if not, how much would remain of CARB and the District's unfulfilled aggregate tonnage commitments.

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025

| | | $NO_X$ (tpd) | Direct $PM_{2.5}$ (tpd) |
|---|---|---|---|
| A | Total reductions needed from baseline and control strategy measures (see Table 1, row A of this proposed rule). | 207.38 | 6.4 |
| B | Total reductions remaining as commitments after SIP credit (see Table 1, row D of this proposed rule). | 28.59 | 0.51 |
| | *CARB:* | | |
| | *Submitted Measures:* | | |
| | HDVIP and PSIP [a] | 0 | 0.02 |
| | Innovative Clean Transit | 0.017 | <<0.01 |
| C | Sub-Total | 0.017 | 0.02 |
| | *Additional Adopted Measures:* | | |
| | Heavy-Duty I/M | 14.7 | 0.03 |
| | Amended Warranty Requirements for Heavy-Duty Vehicles | 0.34 | <<0.01 |
| | Heavy-Duty Low-$NO_X$ Engine Standard—California Action | 0 | 0 |
| | Advanced Clean Local Trucks (Last Mile Delivery) | 0.08 | <<0.01 |
| | Zero-Emission Airport Shuttle Buses | <<0.01 | <<0.01 |
| | Small Off-Road Engines | 0.155 | 0.007 |
| | Transport Refrigeration Units Used for Cold Storage | 0.04 | 0.01 |
| | Agricultural Equipment Incentive Measure-Phase 1 (NRCS portion) | 0.64 | 0.04 |
| | Agricultural Equipment Incentive Measure Phase 2 | 4.9 | 0.5 |
| D | Sub-Total | 15.955 | 0.087 |
| | *Measures Not Yet Presented for Board Consideration:* [b] | | |
| | Zero-Emission Off-Road Forklift Regulation Phase 1 | 0.02 | <<0.01 |
| E | Sub-Total | 4.92 | 0.5 |
| F | *Grand Total for CARB (C+D+E)* | 20.892 | 0.607 |
| | *SJVUAPCD:* | | |
| | *Submitted Measures:* | | |
| | Rule 4311 (''Flares'') | 0.19 | 0.03 |
| | Rule 4306 (''Boilers, Steam Generators, and Process Heaters—Phase 3'') | 0.19 | 0 |
| | Rule 4320 (''Advanced Emission Reduction Option for Boilers, Steam Generators, and Process Heaters greater than 5 MMBtu/hr'') [c]. | 0 | 0 |
| | Rule 4352 (''Solid Fuel Fired Boilers, Steam Generators, and Process Heaters'') | 0.5 | 0.04 |
| | Rule 4354 (''Glass Melting Furnaces'') | 0.2 | 0.04 |

[189] However, we note that if the EPA were to grant maximum credit for the emission reductions calculated by the District for Rule 4311 (0.19 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$), the remaining aggregate tonnage commitments would be 28.4 tpd $NO_X$ (13.7% of total reductions needed to attain in 2025) and 0.48 tpd direct $PM_{2.5}$ (7.5% of total reductions needed to attain in 2025).

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025—Continued

| | | $NO_X$ (tpd) | Direct $PM_{2.5}$ (tpd) |
|---|---|---|---|
| | Rule 4702 (''Internal Combustion Engines'') | 0.61 | 0 |
| | Residential Wood Burning Incentive Measure | 0 | 0.33 |
| G | Sub-Total | 1.69 | 0.44 |
| | *Measures Not Yet Presented for Board Consideration:* | | |
| | Rule 4550 (''Conservation Management Practices'') | 0 | 0.32 |
| H | Sub-Total | 0 | 0.32 |
| I | *Grand Total for SJVUAPCD (G+H)* | 1.69 | 0.76 |
| J | *Grand Total (F+I)* | 22.58 | 1.37 |
| K | Assuming maximum SIP credit, total reductions remaining as commitments (B–J) | 6.01 | −0.86 |

Sources: 2021 Progress Report, Table 2 and Table 3.

[a] As discussed herein, the EPA has taken final action to approve CARB's HDVIP and PSIP measure into the California SIP but we are not yet proposing SIP credit for these two measures.

[b] Given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

[c] The District's draft staff report for Rule 4306 and Rule 4320 estimate emission reductions of 0.19 tpd $NO_X$ and 0.45 tpd $NO_X$, respectively, in 2024. However, the District notes that it is not proposing the emission reductions from Rule 4320 for SIP credit at this time. SJVUAPCD, ''Draft Staff Report, Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters—Phase 3), Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr),'' November 25, 2020, 4.

Assuming the EPA were to agree with the maximum credit for the emission reductions estimated by CARB and the District in the 2021 Progress Report, these additional measures could achieve emission reductions of 22.58 tpd $NO_X$ and 1.37 tpd direct $PM_{2.5}$. Combined with the reductions from additional measures already approved by EPA into the California SIP (5.29 tpd $NO_X$ and 1.69 tpd direct $PM_{2.5}$, per Row C of Table 1 of this proposed rule), the State would achieve emission reductions of 27.87 tpd $NO_X$ and 3.06 tpd direct $PM_{2.5}$. Compared to the combined aggregate tonnage commitments, the State would have remaining aggregate tonnage commitments of 6.01 tpd $NO_X$ and would have exceeded the aggregate tonnage commitments by 0.86 tpd direct $PM_{2.5}$. More specifically, CARB would have remaining commitments of 6.65 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$, and the District would have exceeded its commitments by 0.64 tpd $NO_X$ and 0.89 tpd direct $PM_{2.5}$.

However, given the remaining $NO_X$ commitments for CARB, which are approximately 3% of the $NO_X$ emission reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by 2025, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures, including the NRCS portion of the Phase 1 measure adopted by CARB in 2019 and the Phase 2 measure slated for 2024 consideration, per the 2021 Progress Report.

With respect to Heavy-Duty I/M, in the Valley State SIP Strategy, CARB originally estimated that it would achieve 6.8 tpd $NO_X$ and <0.1 tpd direct $PM_{2.5}$ in 2025 and described the regulatory concepts that would reflect the current (as of 2018) ''advanced engine and exhaust control technologies, including on-board diagnostics (OBD).''[190] Since that time, as described in the State's 2021 Progress Report and the EPA's 2021 Proposed Rule, California has developed additional provisions related to Heavy-Duty I/M that the State estimates would achieve emission reductions of 14.7 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$ in 2025.[191]

While the EPA would still not propose to approve a specific amount of SIP-creditable reductions until after the State submits such measure in final form to the EPA as a revision to the SIP, we have re-examined the role of the potential additional emission reductions from Heavy-Duty I/M presented by CARB. As a qualitative matter, we agree that the requirements under California Senate Bill 210 (2019) that heavy-duty vehicles comply with Heavy-Duty I/M in order to register annually with the California Department of Motor Vehicles, as well as the implementation of roadside emissions monitoring (*i.e.,* the Portable Emissions AcQuisition System, ''PEAQS'') in the SJV to detect high emitting vehicles between periodic test cycles, are tangible additions that would increase the emission reductions relative to what was contemplated at the time of Plan adoption in November 2018 (by the District) and January 2019 (by CARB).

As a quantitative matter, however, the scale of the estimated 14.7 tpd $NO_X$ emission reductions is roughly half the remaining aggregate commitment of 28.59 tpd $NO_X$ and represents 7.1% of the 207.38 tpd $NO_X$ modeled for attainment and a substantial increase from CARB's original estimate of 6.8 tpd $NO_X$ (3.3% of the 207.38 tpd $NO_X$). This 14.7 tpd $NO_X$ represents a substantial quantity that, pursuant to the Ninth Circuit Memorandum Opinion, must be supported by evidence to ''ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy'' in order to satisfy the second factor of the three-factor aggregate commitment test.[192] While CARB documented its extensive regulatory and technical

[190] Valley State SIP Strategy, 19–20 and Table 8.

[191] 2021 Progress Report, 19. CARB notes that further detail on emission reduction calculations can be found in the CARB staff report on Heavy-Duty I/M, released October 15, 2021. See, CARB, ''Staff Report: Initial Statement of Reasons, Public Hearing to Consider the Proposed Heavy-Duty Inspection and Maintenance Regulation,'' October 8, 2021, (''Heavy-Duty I/M ISOR'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[192] See *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7 (9th Cir., April 13, 2022).

analyses in the measure's Initial Statement of Reasons and associated appendices,[193] CARB has not provided the detailed basis of its calculations of 14.7 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$ emission reductions to the EPA. Given that CARB may do so in a future control measure SIP submission, and we lack the record evidence to do so here, we do not suggest an alternative amount of emission reduction from Heavy-Duty I/M in this proposed rule. Rather, we note that the more detailed calculations and technical report necessary to support such an estimate, specific to the SJV and to annual average emission reductions in 2025, are not available, and therefore we do not have sufficient support in the record at this time to rely on the State's estimated reductions, in line with the Ninth Circuit Memorandum Opinion.

With respect to mobile agricultural equipment, the EPA has taken final action to approve the Funding Agricultural Replacement Measures for Emission Reductions (FARMER) program and the Carl Moyer Memorial Air Quality Standards Attainment Program (''Carl Moyer'') portions of CARB's first incentive measure on agricultural equipment in the SJV (''Agricultural Equipment Incentive Measure-Phase 1'') and proposed in our 2021 Proposed Rule to credit emission reductions of 4.46 tpd $NO_X$ and 0.26 tpd direct $PM_{2.5}$ towards CARB's aggregate tonnage commitments.[194] CARB has estimated that it will achieve 4.9 tpd additional $NO_X$ reductions, and 0.5 tpd additional direct $PM_{2.5}$ reductions through a second agricultural equipment incentive measure. In light of the Ninth Circuit Memorandum Opinion, and its finding that the EPA had not ensured that CARB and the District had a ''plausible strategy'' for achieving parts of the attainment strategy that relied on incentive-based reductions in the face of a budget shortfall for funding these measures, we must evaluate whether there is sufficient evidence in the record to establish a reasonable basis for concluding that any ''Phase 2'' agricultural equipment incentive measure will have sufficient funding to achieve the reductions ascribed to it.

As we noted in the EPA's 2021 Proposed Rule, fewer incentive-based emission reductions are needed to demonstrate attainment of the 2012 annual $PM_{2.5}$ NAAQS than were required in the portion of the SJV $PM_{2.5}$ Plan addressing the 2006 24-hour $PM_{2.5}$ NAAQS that was at issue in the *Medical Advocates* case.[195] In the Ninth Circuit Memorandum Opinion, the court pointed to a $2.6 billion shortfall between what the EPA calculated to be a need for $5 billion in funding and the more than $2 billion in funding that the State had ''identified or anticipated.''[196] Notably, funding for the Carl Moyer, California Assembly Bill 617, and FARMER programs were included in the ''identified or anticipated'' portion of the State's funding analysis, and not the ''incentive funding gap'' for which the Court found EPA's explanations justifying approval to be overly speculative.[197] Accordingly, we do not consider reliance on reductions from a Phase 2 agricultural equipment incentive measure to be prohibited by the Ninth Circuit Memorandum Opinion, to the extent that a Phase 2 rule would rely on the same, existing programs, and provided that evidence of sufficient identified or reasonably anticipated funding exists in the record.

As described in the EPA's analysis of the cost-effectiveness of the Agricultural Equipment Incentive Measure-Phase 1, based on information provided by CARB, the total project costs resulting in these emission reductions were $155 million for FARMER and $125 million for Carl Moyer, or $280 million combined.[198] As described in the EPA's 2021 Proposed Rule,[199] the SJV portion of the FARMER funding has typically been 80% of the State-wide allocation and the first three years of FARMER funding for the SJV were $108 million (fiscal year 2017–2018), $104.3 million (fiscal year 2018–2019), and $43.84 million (fiscal year 2019–2020).[200] For the current fiscal year (2021–2022), the District accepted $168.43 million in FARMER funds to replace agricultural equipment in the SJV.[201] Similarly, we noted that CARB expects Carl Moyer funding to increase in future years, following the enactment of California Assembly Bill 1274.[202]

Thus, while future funding allocations are subject to annual State and local funding cycles, given the renewed, large investment in the fiscal year 2021–2022 FARMER program, potential for increases in funding for the Carl Moyer program, and the success of these programs in meeting enforceability criteria for purposes of crediting emission reductions, the EPA anticipates that CARB will be able to develop an additional agricultural equipment incentive measure (''Agricultural Equipment Incentive measure-Phase 2'') that has funding levels comparable or larger than those for Phase 1 (*i.e.,* including the $168 million accepted by the District in March 2022) and that CARB's emission reduction estimates of 4.9 tpd $NO_X$ and 0.5 tpd direct $PM_{2.5}$ by 2025, per the 2021 Progress Report, are reasonable and supported by identified or reasonably anticipated funding.

However, we have not yet taken final action on the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1 and, for this proposed rule, do not rely on the estimated emission reductions for that portion of the Agricultural Equipment Incentive Measure-Phase 1 (*i.e.,* 0.64 tpd $NO_X$ and 0.04 tpd direct $PM_{2.5}$). Looking forward in time, this suggests some uncertainty regarding creditability of emission reductions from any portion of a Phase 2 agricultural equipment incentive measure that may be implemented through the NRCS program.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reductions estimated may be warranted in certain cases.[203] Accordingly, the overall remaining $NO_X$ commitment could be larger than 6.01 tpd and the anticipated

[193] Heavy-Duty I/M ISOR and, for example, Heavy-Duty I/M ISOR, App. D (''Emissions Inventory Methods and Results, Proposed Heavy-Duty Inspection and Maintenance Regulation'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[194] 86 FR 74310, 74332; 86 FR 73106, 73109.

[195] 86 FR 74310, 74330. This is due to greater-than-expected reductions from committed to and substitute non-incentive regulatory measures, such as the Agricultural Burning Phase-Out Measure.

[196] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7; 85 FR 44192, 44201.

[197] CARB Staff Report, 27 (Table 9).

[198] Memorandum dated June 22, 2020, from Rebecca Newhouse, EPA Region IX, to docket number EPA–R09–OAR–2019–0318, Subject: ''Cost-effectiveness of Emission Reductions from the Valley Incentive Measure and Estimated Future Funding Needs for Additional Agricultural Equipment Replacements'' (''EPA Cost-Effectiveness Memo'').

[199] 86 FR 74310, 74337.

[200] CARB, ''Funding Agricultural Replacement Measures for Emission Reductions (FARMER) Program, San Joaquin Valley APCD,'' as reported through September 30, 2020.

[201] SJVUAPCD, ''Item Number 9: Accept $168,425,600 in State FARMER Program Funds for Use in the District's Agricultural Equipment Replacement Project,'' March 17, 2022.

[202] 2021 Progress Report, 22.

[203] For example, the District originally sought SIP credit of 0.26 tpd direct $PM_{2.5}$ emission reductions from Rule 4901 and the EPA is proposing 0.2 tpd direct $PM_{2.5}$ based on a 75% rule effectiveness rate. Similarly, CARB and the District sought SIP credit of 1.04 tpd $NO_X$ and 1.54 tpd direct $PM_{2.5}$ emission reductions from the Agricultural Burning Phase-out Measure and the EPA is proposing 0.83 tpd $NO_X$ and 1.23 tpd direct $PM_{2.5}$ based on an 80% rule effectiveness rate.

excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Notwithstanding some uncertainty as to the scale of emission reductions from the Heavy-Duty I/M and the Agricultural Equipment Incentive Measures (*i.e.,* assuming that the additional measures with discrete emission reduction estimates in the 2021 Progress Report achieve their respective emission reductions), there remains at least 6.65 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$ in CARB's commitment for which the record does not contain a specific and plausible strategy to achieve. In our 2021 Proposed Rule we discussed two possible ways that CARB could fill this gap: (1) additional reductions from committed or substitute measures named by CARB, and (2) a hypothetical inter-pollutant trading of excess direct $PM_{2.5}$ emission reductions by the District for any shortfall in $NO_X$ emission reductions by CARB. The Ninth Circuit Memorandum Opinion has established that these concepts in the absence of a specific SIP revision are too speculative and do not constitute a ''plausible strategy'' for achieving this portion of the commitment.

With respect to additional reductions from committed measures, in the 2021 Proposed Rule, we explored potential reductions from two incentive-based measures: Accelerated Turnover of Trucks and Buses Incentive Projects, and Accelerated Turnover of Off-road Equipment Incentive Projects.[204] CARB initially estimated that they would achieve 8 tpd $NO_X$ reductions from Accelerated Turnover of Trucks and Buses Incentive Projects, and 1.5 tpd $NO_X$ reductions from Accelerated Turnover of Off-road Equipment Incentive Projects.[205] However, CARB did not propose a measure to its board for either measure by 2021, as it had committed to do, nor to our knowledge has CARB started the public process for enforceable measures to be submitted to the EPA for inclusion as control measures in the California SIP.

In the 2021 Progress Report, CARB acknowledged that many of the project lives do not span the attainment year[206] and, thus, while these projects accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration. In our 2021 Proposed Rule, we acknowledged these weaknesses in these incentive programs, but we nonetheless assumed that these measures may ultimately result in SIP-creditable emission reductions for a portion of the combined 9.5 tpd $NO_X$.[207] In light of the Ninth Circuit Memorandum Opinion, the EPA does not consider it appropriate to rely on reductions that have been rendered substantially less likely to occur by the State's update indicating that few emissions from these projects may be creditable.

Furthermore, while the State continues to invest heavily in the replacement of older, dirty heavy-duty vehicles and equipment on a State-wide basis,[208] we are not aware of a document that identifies specific funding amounts applied to the replacement of such equipment in the SJV within the specific timeline of the Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025. In brief, the amount of funding that is specific to the SJV for these two measures for purposes of attainment of the 2012 annual $PM_{2.5}$ NAAQS is unclear, and this renders more speculative at least a portion of the large scale of $NO_X$ emission reductions originally anticipated.[209]

With respect to substitute measures under development, CARB points to the In-Use Locomotive Rule (and estimates emission reductions of 1.14 tpd $NO_X$ and 0.03 tpd direct $PM_{2.5}$ by 2025 in the SJV), which is slated for 2022 Board consideration.[210] However, as noted in our 2021 Proposed Rule,[211] given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

In addition, CARB has identified further measures that were not included in the original control measure commitments that may provide emission reductions toward CARB's aggregate tonnage commitments.[212] These measures include Cargo Handling Equipment Registration, Construction and Mining Equipment Measure, and Co-Benefits from the Climate Program. However, we do not have information as to what these measures might entail, when the State may adopt or implement them, and what scale of emission reductions they could potentially achieve.

Based on the lack of information on funding and process for heavy-duty and off-road equipment incentive-based measures and the lack of information on other potential substitute measures, such as a Construction and Mining Equipment Measure, and in light of the Ninth Circuit Memorandum Opinion, we have reconsidered our evaluation of this prospect and now propose that there is not sufficient evidence to show that the Valley State SIP Strategy contains a ''plausible strategy'' to achieve the remaining $NO_X$ and direct $PM_{2.5}$ emission reductions needed for attainment.

The other approach that the 2021 Proposed Rule discusses for filling the gap in CARB's strategy for achieving its commitment is based on a hypothetical future SIP revision. In the 2021 Progress Report, CARB and the District provided additional emissions analysis to assess how excess direct $PM_{2.5}$ emission reductions could be converted to equivalent $NO_X$ emission reductions using an inter-pollutant trading ratio rooted in the sensitivity analyses of the 2018 $PM_{2.5}$ Plan.[213] CARB and the District have not formally submitted this analysis as a SIP revision to the EPA or requested that the EPA apply such inter-pollutant trading for purposes of fulfilling the aggregate tonnage commitments through an equivalent amount of emission reductions.

Consistent with past EPA action on $PM_{2.5}$ planning SIP submissions for the SJV,[214] where the State submits a SIP

[204] 86 FR 74310, 74335.

[205] Valley State SIP Strategy, Table 7.

[206] 2021 Progress Report at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

[207] 86 FR 74310, 74335.

[208] See, *e.g.,* CARB, ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives, Appendix D: Long-Term Heavy-Duty Investment Strategy,'' release date October 8, 2021.

[209] The EPA also notes that, for regulatory measures that have large estimated emission reductions, rather than incentive-based measures, CARB estimated that its Low-Emission Diesel Fuel Requirement would achieve an additional 1 tpd $NO_X$ and 0.1 tpd direct $PM_{2.5}$ reductions. However, without near-term adoption and submission, its associated emission reductions may not be creditable towards the aggregate tonnage commitment for 2025.

[210] 2021 Progress Report, 20–21. Additional information on CARB's regulatory concepts for the In-Use Locomotive Measure are available at: *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california/locomotives-and-railyards-meetings-workshops.*

[211] 86 FR 74310, 74334, fn. 228.

[212] CARB, ''SJV $PM_{2.5}$ SIP Measure Tracking,'' September 2021, 3. Available at: *https://ww2.arb.ca.gov/resources/documents/2018-san-joaquin-valley-pm25-plan.*

[213] 2021 Progress Report, Table 4 and 33–37.

[214] For example, the EPA has approved an inter-pollutant trading mechanism for use in transportation conformity analyses for the 2006 24-hour $PM_{2.5}$ NAAQS. 85 FR 44192, 44204. In that same final rule, the EPA approved the State's demonstration that it had fulfilled prior aggregate tonnage commitments, in part, by using an inter-pollutant trading approach that the EPA found

revision that would substitute reductions in one pollutant to achieve a tonnage commitment concerning a different pollutant (*e.g.,* substituting excess direct $PM_{2.5}$ reductions to satisfy a $NO_X$ reduction commitment), it must include an appropriate inter-pollutant trading (IPT) ratio and the technical basis for such ratio in the plan submission itself, along with the requisite public process. The EPA will review any such IPT ratio and its bases before approving or disapproving any such SIP revision. The possibility of a future SIP submission discussing IPT does not constitute a ''plausible strategy'' for achieving reductions that are modeled to result in attainment. Thus, at this time, we are not proposing to approve any particular inter-pollutant trading approach for purposes of meeting the aggregate tonnage commitments, nor applying any excess reductions of one pollutant towards fulfilling a portion of committed reductions of the other pollutant.

The additional evaluation we have discussed herein as part of our reconsideration of the State's enforceable commitments requires us to re-evaluate the EPA's three-factor test for enforceable commitments. Based on our reconsideration, and consistent with the Ninth Circuit Memorandum Opinion, we retain our proposed findings that the State's commitments meet the first factor (the commitment represents a limited portion of the required reductions, *i.e.,* 13.8% of the $NO_X$ and 8.0% of the direct $PM_{2.5}$ emission reductions necessary to attain) and the third factor (the commitment is for a reasonable and appropriate timeframe) of the three-factor test. However, we now propose that the State's commitments do not meet the second factor (regarding the State's capability to fulfill its commitments). Our analysis and findings for the first and third factors are presented in section IV.F.3.e of the 2021 Proposed Rule. We provide our reconsidered evaluation of the second factor as follows in this proposed rule.

As the EPA noted in our 2021 Proposed Rule, CARB and the District have been capable of developing and adopting many of the regulatory measures listed in their respective control measure commitments. However, the question before us more precisely is whether such substantial progress, coupled with the strategy submitted by the State for achieving the remaining reductions which the State has modeled as leading to attainment, is sufficient to show that the State is capable of fulfilling its *entire* aggregate tonnage commitments by 2025. Several components of our reconsideration suggest that the State may not be capable of fulfilling the entire aggregate tonnage commitment, particularly with respect to $NO_X$ emission reductions from additional CARB measures.

First, in terms of additional measures for which CARB and the District provided updated emission reduction estimates, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures. For Heavy-Duty I/M, CARB has not provided to the EPA a sufficient basis for its increase in estimated emission reductions from 6.8 tpd $NO_X$ to 14.7 tpd $NO_X$, where the 14.7 tpd reduction amounts to 7.1% of the total emission reductions modeled for attainment of the 2012 annual $PM_{2.5}$ NAAQS. Although the EPA is confident, based on its review, that emission reductions are available in this category, and that the State is capable of achieving some amount of reductions, the State has not sufficiently supported its assertion that it is capable of achieving 14.7 tpd of $NO_X$ and 0.03 tpd of direct $PM_{2.5}$. As discussed above, due to uncertainty surrounding the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1, we are not relying on reductions from that portion of the rule, and the creditability of any NRCS portion of a potential future Phase 2 has not been established.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reduction estimates may be warranted in certain cases.

Accordingly, the overall remaining $NO_X$ commitment could be larger than 6.01 tpd and the anticipated excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Second, even if the EPA were to assume maximum credit for the additional measures for which CARB and the District provided updated emission reduction estimates, CARB, in combination with the District, would still need emission reductions of at least 6 tpd $NO_X$ to fulfill its commitments.[215] Moreover, the reductions from CARB's remaining incentive measures for Heavy-Duty vehicles and off-road equipment appear to be limited relative to the combined emission reduction estimate of 9.5 tpd $NO_X$ in the Plan. Without documentation supporting the funding amounts to be applied in the SJV within the timeline of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, it is not clear that the full amount of these estimated reductions is supported by a ''plausible strategy'' to achieve them, as required in the Ninth Circuit Memorandum Opinion. In addition, the identified substitute measures lack sufficient detail to provide support for making up for $NO_X$ emission reduction shortfalls from CARB's control measure commitments.

Given the gap between the reductions needed and the reductions for which CARB and the District have presented a non-speculative plan for achieving, we now propose that the State has not demonstrated that it is capable of fulfilling the remaining aggregate tonnage commitments necessary to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and therefore find that the SJV $PM_{2.5}$ Plan does not meet the second factor of our three-factor test for enforceable commitments.

b. Attainment Demonstration

Based on our reconsideration of the Plan's enforceable commitments described in section II.C.3.a of this proposed rule, and our reconsideration of the Plan's BACM demonstration for described in section II.B, we now propose to disapprove the SJV $PM_{2.5}$ Plan's modeled attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025. We discuss the interrelationship of these nonattainment plan elements as follows.

Regarding enforceable commitments, CAA section 110(a)(2)(A) provides that each SIP ''shall include enforceable emission limitations and other control measures, means or techniques . . . as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of [the Act].'' Section 172(c)(6) of the Act, which applies to nonattainment SIPs, is virtually identical to section 110(a)(2)(A). The EPA interprets the CAA to allow for approval of enforceable commitments that are limited in scope, where circumstances exist that warrant the use of such commitments in place of

adequate. 85 FR 44192, 44205; see also proposed rule at 85 FR 17382, 17406–17407 and associated EPA's General Evaluation TSD, Table III–C and section IV.

[215] As noted in this proposed rule, if the EPA were to assume credit for emission reductions from the additional District measures, the District would have exceeded its aggregate tonnage commitments by 0.64 tpd $NO_X$ and 0.89 tpd direct $PM_{2.5}$.

adopted and submitted measures, and considers three factors in determining whether to approve the enforceable commitment.

Given our proposed finding above that the State has not met the second factor of the EPA's three-factor test (*i.e.,* whether the State is capable of fulfilling its commitment), the State is left with a gap between the reductions that it has modeled as necessary for attainment, and the reductions that the EPA may count as constituting the State's control plan. Therefore, the EPA proposes that the State's control strategy does not include sufficient enforceable measures, pursuant to CAA sections 110(a)(2)(A) and 172(c)(6), to achieve the necessary emission reductions to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025.

The lack of an approved control plan to achieve the reductions necessary to attain by 2025 is sufficient on its own to compel disapproval of the attainment demonstration. However, even if the State's control plan was sufficient to lead to attainment in 2025, the Public Justice Comment Letter and our reconsidered BACM analysis in section II.B of this notice raise additional issues regarding the sufficiency of the modeled attainment demonstration.

The State's attainment demonstration identifies the Bakersfield-Planz monitor as the design value monitor, and models this monitor as achieving the 12.0 µg/m³ concentration necessary for attainment in 2025.[216] The State's submission also indicates that the Bakersfield-Planz monitor is modeled to read 12.1 µg/m³ in 2024.[217] This represents a very narrow margin between modeled attainment in 2024 and 2025. In light of the Act's requirement to demonstrate attainment by the most expeditious date practicable, in order for the EPA to approve the Plan's demonstration that the area will attain by 2025, the State must also demonstrate that attainment by an earlier date is not practicable.

As explained in section II.B of this notice, the EPA now proposes to find that the State has not sufficiently demonstrated that it has implemented BACM for all necessary categories of sources. Most notably, the State has not sufficiently evaluated the amount of ammonia reductions that may be available. In light of the very small (0.1 µg/m³) gap between attaining in 2024 and 2025, and the State's sensitivity modeling in its precursor demonstration indicating that a 30% reduction in ammonia would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.12 µg/m³ and a 70% reduction would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.36 µg/m³, the State has not demonstrated that reductions from sources identified in section II.B could not expedite attainment.[218] As a result, even if the State's control plan was sufficiently concrete that the EPA could credit all reductions of $NO_X$ and direct $PM_{2.5}$ that the State indicated that it intended to use to fulfill its aggregate commitments, the State is still required to demonstrate that the selected attainment year (*e.g.,* 2025) is as expeditious as practicable considering potential emission reductions from all plan precursors, including ammonia.

The EPA emphasizes that it is stating both that the Plan does not demonstrate that the SJV will attain by 2025 and that the State has not demonstrated that it could not attain sooner than 2025. These findings are not in tension with one another. Under the Act, the State must demonstrate that its control plan will be sufficient to attain the NAAQS, and to attain the NAAQS by the most expeditious date practicable. The State's failure to demonstrate that it could not attain sooner than 2025 is not inconsistent with the State also having other analytical or substantive flaws in its control plan to attain by 2025. The EPA is not proposing to find that the SJV can practicably attain by 2024, nor is the EPA proposing to find that the SJV could not possibly attain by 2025. Instead, the EPA is proposing, in light of the uncertainty regarding ammonia controls, to find that the State has failed to demonstrate that it could not practicably attain before 2025, and in light of identified deficiencies in the control plan, that the State's control strategy for attaining by 2025 is flawed.

Furthermore, for the 1997 annual $PM_{2.5}$ NAAQS, on November 8, 2021, the State submitted the ''Attainment Plan Revision for the 1997 Annual $PM_{2.5}$ Standard,'' which was adopted by the District on August 19, 2021, and by CARB on September 23, 2021 (''15 µg/m³ SIP Revision''). In that submission, the State updated its prior air quality modeling to account for more recent monitored air quality data. Specifically, the State estimated 2023 annual average concentrations starting from a 2018 monitored base year (*i.e.,* rather than a 2013 base year, in order to reflect updated monitored air quality data), and applied updated, scaled relative response factors (RRFs) to reflect emissions changes between 2018 and 2023.[219] Because this scaling indicated a significant change in the modeling results for the 1997 annual $PM_{2.5}$ NAAQS, and the modeling for the 2012 annual $PM_{2.5}$ NAAQS relies on many of the same models and assumptions, the result of the scaling analysis introduces additional uncertainty to the modeled attainment demonstration for the 2012 $PM_{2.5}$ NAAQS. Accordingly, we recommend updated modeling analysis for the 2012 annual $PM_{2.5}$ NAAQS.

As a result of our proposed disapproval of the control plan and the uncertainty regarding additional reductions that could be achieved by further BACM/BACT level controls for all appropriate plan precursors (particularly for ammonia), we now propose to disapprove the attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS.

### *D. Reasonable Further Progress Demonstration and Quantitative Milestones*

1. Summary of 2021 Proposed Rule

In section IV.G of our 2021 Proposed Rule, the EPA described the requirements for RFP and quantitative milestones for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[220] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.D.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for RFP and quantitative milestones).

Regarding requirements, CAA section 172(c)(2) provides that all nonattainment area plans shall require RFP toward attainment. In addition, CAA section 189(c) requires that all $PM_{2.5}$ nonattainment area plans contain quantitative milestones for purposes of measuring RFP, as defined in CAA section 171(1), every three years until the EPA redesignates the area to attainment. Section 171(1) of the Act defines RFP as the annual incremental reductions in emissions of the relevant air pollutant as are required by part D, title I of the Act, or as may reasonably be required by the Administrator for the purpose of ensuring attainment of the

[216] 2018 $PM_{2.5}$ Plan, App. K, Table 39.

[217] Id. at Table 33.

[218] See 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[219] 15 µg/m³ SIP Revision, Ch. 5, 5–9 to 5–12. See also 15 µg/m³ SIP Revision, App. K, 64–65. In the 15 µg/m³ SIP Revision, the State used existing modeling runs for 2020 and 2024 to compute RRFs for each $PM_{2.5}$ component using the standard approach recommended in the EPA's Modeling Guidance. Those RRFs were then scaled to reflect emissions changes between 2018 and 2023 to arrive at updated RRFs.

[220] 86 FR 74310, 74338–74345.

NAAQS by the applicable attainment date.

In addition to the EPA's longstanding guidance on the RFP requirements for PM, the Agency has established specific regulatory requirements for the $PM_{2.5}$ NAAQS in the $PM_{2.5}$ SIP Requirements Rule for purposes of satisfying the Act's RFP requirements and provided related guidance in the preamble to the rule. Specifically, under the $PM_{2.5}$ SIP Requirements Rule, for a $PM_{2.5}$ attainment plan a State must include an RFP analysis that includes, at minimum, the following four components: (1) an implementation schedule for control measures; (2) RFP projected emissions for direct $PM_{2.5}$ and all $PM_{2.5}$ plan precursors for each applicable milestone year, based on the anticipated control measure implementation schedule; (3) a demonstration that the control strategy and implementation schedule will achieve reasonable progress toward attainment between the base year and the attainment year; and (4) a demonstration that by the end of the calendar year for each triennial milestone date for the area, pollutant emissions will be at levels that reflect either generally linear progress or stepwise progress in reducing emissions on an annual basis between the base year and the attainment year.[221] Additionally, states should estimate the RFP projected emissions for each quantitative milestone year by sector on a pollutant-by-pollutant basis.[222]

Section 189(c) of the Act requires that $PM_{2.5}$ attainment plans include quantitative milestones that demonstrate RFP. The purpose of the quantitative milestones is to allow periodic evaluation of the State's progress towards attainment of the $PM_{2.5}$ NAAQS in the area consistent with RFP requirements. Because RFP is an annual emission reduction requirement and the quantitative milestones are to be achieved every three years, when a State demonstrates compliance with the quantitative milestone requirement, it should also demonstrate that RFP has been achieved during each of the relevant three years. Quantitative milestones should provide an objective means to evaluate progress toward attainment meaningfully, *e.g.,* through imposition of emissions controls in the attainment plan and the requirement to quantify those required emissions reductions on the schedule approved by the EPA and thus required to meet RFP.

As we noted in the 2021 Proposed Rule, the CAA does not specify the starting point for counting the three-year periods for quantitative milestones under CAA section 189(c). In the General Preamble and General Preamble Addendum, the EPA interpreted the CAA to require that the starting point for the first three-year period be the due date for the Moderate area plan submission.[223] Consistent with this longstanding interpretation of the Act, the $PM_{2.5}$ SIP Requirements Rule requires that each plan for a Serious $PM_{2.5}$ nonattainment area that demonstrates attainment by the end of the 10th calendar year following the date of designation contain quantitative milestones to be achieved no later than milestone dates 7.5 years and 10.5 years from the date of designation of the area.[224] The 2018 $PM_{2.5}$ Plan includes a demonstration designed to show attainment by the end of the 10th calendar year following designations (*i.e.,* December 31, 2025). Because the EPA designated the SJV nonattainment for the 2012 annual $PM_{2.5}$ NAAQS effective April 15, 2015,[225] the applicable quantitative milestone dates for purposes of the submitted Serious area plan for this NAAQS in the SJV are October 15, 2022, and October 15, 2025.

Quantitative milestones must provide for objective evaluation of reasonable further progress toward timely attainment of the $PM_{2.5}$ NAAQS in the area and include, at minimum, a metric for tracking progress achieved in implementing SIP control measures, including BACM and BACT, by each milestone date.[226]

The State presents its RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS in Appendix H of the 2018 $PM_{2.5}$ Plan. Following the identification of a transcription error in the RFP tables of Appendix H, the State submitted a revised version of Appendix H that corrects the transcription error and provides additional information on the RFP demonstration.[227] Given the State's conclusions that ammonia, $SO_X$, and VOC emissions do not contribute significantly to $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the RFP demonstration provided by the State only addresses emissions of direct $PM_{2.5}$ and $NO_X$.[228] Similarly, the State developed quantitative milestones based upon the Plan's control measure strategy to achieve emission reductions of direct $PM_{2.5}$ and $NO_X$.[229]

For the 2012 annual $PM_{2.5}$ NAAQS, the RFP demonstration in the Plan follows a stepwise approach due to the time required for CARB and the District ''to amend rules, develop programs, and implement the emission reduction measures.'' [230] The revised Appendix H provides clarifying information on the RFP demonstration, including additional information to justify the Plan's stepwise approach to demonstrating RFP. This clarifying information did not affect the Plan's quantitative milestones. It is important to note that the State evaluated what would be necessary for purposes of meeting RFP premised upon its approach to regulating only direct $PM_{2.5}$ and $NO_X$ emissions, and upon a December 31, 2025 attainment date that itself depended upon the State achieving certain additional emission reductions though the enforceable commitments.

In our 2021 Proposed Rule we further described the State's RFP demonstration and quantitative milestones in the SJV $PM_{2.5}$ Plan, including, for example, the anticipated implementation schedule for CARB and District control measures, projected emissions for each RFP year and attainment year, and percent reductions to be achieved in each milestone year, which would be consistent with a stepwise approach. We noted that the reductions between the 2013 base year and 2019 milestone year are consistent with generally linear progress toward the targeted attainment date, while the reductions by the 2022 milestone year would fall short of the rate of reductions to show generally linear RFP. We also noted that the State relies on more substantial direct $PM_{2.5}$ and $NO_X$ emission reductions by January 1, 2025, due in large part to CARB and the District's reliance on enforceable commitments to achieve additional $PM_{2.5}$ and $NO_X$ emission reductions from new measures implemented by 2024. Lastly, we noted the State's overall conclusion that the adopted control strategy and additional commitments for reductions from new control programs by this time are adequate to meet the RFP requirement for the 2012 annual $PM_{2.5}$ NAAQS with

[221] 40 CFR 51.1012(a).

[222] 81 FR 58010, 58056.

[223] General Preamble, 13539 and General Preamble Addendum, 42016.

[224] 40 CFR 51.1013(a)(2)(i).

[225] 80 FR 2206.

[226] 81 FR 58010, 58064 and 58092.

[227] Appendix H to 2018 $PM_{2.5}$ Plan, submitted February 11, 2020, via the EPA State Planning Electronic Collaboration System. This revised version of Appendix H replaces the version submitted with the 2018 $PM_{2.5}$ Plan on May 10, 2019. All references to Appendix H in this proposed rule are to the revised version of Appendix H submitted February 11, 2020.

[228] 2018 $PM_{2.5}$ Plan, App. H, H–1.

[229] Id. at App. H, H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[230] Id. at App. H, H–4.

the projected attainment date of December 31, 2025.

Regarding quantitative milestones, Appendix H of the 2018 $PM_{2.5}$ Plan identifies October 15 milestone dates for the 2019 and 2022 RFP milestone years, the 2025 attainment year, and a post-attainment milestone year of 2028.[231] Appendix H also identifies target emissions levels to meet the RFP requirement for direct $PM_{2.5}$ and $NO_X$ emissions for each of these milestone years,[232] as shown in Table 6 of our 2021 Proposed Rule, and control measures that CARB and the District already have in place or plan to implement by each of these years, in accordance with the control strategy in the Plan.[233]

We noted, however, that while quantitative milestones are required for 2019 in the context of the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (corresponding to the 4.5 years after the date of designation), we have already evaluated and approved the State's quantitative milestones for 2019, as supplemented by the 2018 $PM_{2.5}$ Plan.[234] Therefore, the EPA is not evaluating the 2019 milestones for purposes of the State's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Although the State's attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS does not rely on CARB's and the District's control measure commitments for emission reductions until 2024,[235] the RFP and quantitative milestone elements of the 2018 $PM_{2.5}$ Plan rely on these control measure commitments to demonstrate that the plan requires RFP toward attainment.[236] In our 2021 Proposed Rule we summarized the specific milestones identified by the State for each milestone year and with respect to the control measure commitments in each three-year period.

The EPA presented its evaluation of the State's RFP demonstration and quantitative milestones in section IV.G.3 of the 2021 Proposed Rule, with additional information in section V of the EPA's 2012 Annual $PM_{2.5}$ TSD. We previously proposed to approve the State's RFP demonstration and quantitative milestones.

2. The EPA's Reconsidered Proposal

As discussed in section II.C.3, we are now proposing to disapprove the attainment demonstration for the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS because we are proposing to not approve the State's control plan to achieve the reductions modeled for 2025 and the attainment demonstration does not demonstrate that the SJV could not practicably attain before 2025. The RFP demonstration in the Plan is deficient because it sets out a timeline for implementing the deficient control plan, which is not sufficient to ''ensure attainment'' under CAA section 171(l). The quantitative milestones do not ''demonstrate [RFP] toward attainment by the applicable date'' under CAA section 189(c), both because the Plan does not sufficiently demonstrate that the control plan will result in attainment, and because the plan does not sufficiently establish what the applicable date should be.[237] As a result, the EPA proposes to disapprove the Plan's Serious area RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS.

*E. Motor Vehicle Emission Budgets*

1. Summary of 2021 Proposed Rule

In section IV.I of our 2021 Proposed Rule, the EPA described the requirements for motor vehicle emission budgets (''budgets'') for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[238] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.E.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for budgets).

Section 176(c) of the CAA requires federally funded or approved actions in nonattainment and maintenance areas to conform to the SIP's goals of eliminating or reducing the severity and number of violations of the NAAQS and achieving expeditious attainment of the NAAQS. Conformity to the SIP's goals means that such actions will not: (1) cause or contribute to new violations of a NAAQS; (2) increase the frequency or severity of an existing violation; or (3) delay timely attainment of any NAAQS or any interim milestone.

Actions involving Federal Highway Administration (FHWA) or Federal Transit Administration (FTA) funding or approval are subject to the EPA's transportation conformity rule, codified at 40 CFR part 93, subpart A (''Transportation Conformity Rule''). Under this rule, metropolitan planning organizations (MPOs) in nonattainment and maintenance areas coordinate with State and local air quality and transportation agencies, the EPA, FHWA, and FTA to demonstrate that an area's regional transportation plan (RTP) and transportation improvement programs (TIP) conform to the applicable SIP. The MPO's demonstration is typically done by showing that estimated emissions from existing and planned highway and transit systems are less than or equal to the applicable budgets contained in adequate or approved control strategy implementation plans. An attainment plan for the $PM_{2.5}$ NAAQS should include budgets for the attainment year and each required RFP milestone year for direct $PM_{2.5}$ and $PM_{2.5}$ precursors subject to transportation conformity analyses. Budgets are generally established for specific years and specific pollutants or precursors and must reflect all of the motor vehicle control measures contained in the attainment and RFP demonstrations.[239]

In our 2021 Proposed Rule, we described how states should identify budgets for direct $PM_{2.5}$, $NO_X$, and all other $PM_{2.5}$ precursors for which the State and/or the EPA has determined that on-road emissions significantly contribute to $PM_{2.5}$ levels in the area for each RFP milestone year and the attainment year if the plan demonstrates attainment.[240] All direct $PM_{2.5}$ SIP budgets should include direct $PM_{2.5}$ motor vehicle emissions from tailpipes, brake wear, and tire wear.

We described the process by which the State and the EPA should determine

[231] 2018 $PM_{2.5}$ Plan, App. H, Table H–12.

[232] Id. at Table H–5.

[233] Id. at H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[234] 86 FR 67343, 67346.

[235] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[236] 2018 $PM_{2.5}$ Plan, App. H, H–4 to H–10 (describing commitments by CARB and SJVUAPCD to adopt additional measures to fulfill tonnage commitments for 2024 and 2025, including ''action'' and ''implementation'' dates occurring before 2024 to ensure expeditious progress toward attainment).

[237] In addition, as discussed in section II.C.3.a of this proposed rule, the EPA notes that of the State's 27 control measure commitments, four regulatory measures and four incentive-based measures are overdue (*i.e.,* were due for board consideration in 2020 or 2021). It is not clear, based on the evidence before the EPA, that such measures will be presented to the CARB and District boards in the 2022 calendar year. Furthermore, to the extent the State relies on substitute measures to ultimately fulfill its aggregate tonnage commitments in 2025 (*e.g.,* the Agricultural Burning Phase-out Measure), the State has not provided quantitative milestones as part of a SIP revision that would provide for periodic evaluation of the State's progress in implementing such substitute measures. In addition, the State has not provided quantitative milestones for ammonia.

[238] 86 FR 74310, 74347–74351.

[239] 40 CFR 93.118(e)(4)(v).

[240] 40 CFR 93.102(b)(2)(iv) and (v).

whether other pollutant emissions (*i.e.,* for re-entrained road dust, VOC, $SO_2$, and ammonia) contribute significantly to the $PM_{2.5}$ nonattainment problem, either with respect to the whole plan or with respect to on-road mobile emissions, and therefore be subject to the transportation conformity requirements (*i.e.,* budgets for such pollutant(s) must be included in the plan). We further noted that transportation conformity trading mechanisms are allowed under 40 CFR 93.124 where a State establishes appropriate mechanisms for such trades and where the basis for the trading mechanism is the SIP attainment modeling that establishes the relative contribution of each $PM_{2.5}$ precursor pollutant.

The EPA's process for determining the adequacy of a budget consists of three basic steps: (1) notifying the public of a SIP submittal; (2) providing the public the opportunity to comment on the budgets during a public comment period; and (3) making a finding of adequacy or inadequacy.[241] The EPA can notify the public by either posting an announcement on the EPA's adequacy website notifying the public that the EPA has received a SIP submission that will be reviewed to determine if the budgets in that submission are adequate for transportation conformity purposes (40 CFR 93.118(f)(1)), or through a **Federal Register** notice of proposed rulemaking when the EPA reviews the adequacy of submitted motor vehicle emission budgets simultaneously with its review and action on the SIP itself (40 CFR 93.118(f)(2)).

The State includes budgets for direct $PM_{2.5}$ and $NO_X$ emissions for the 2019 and 2022 RFP milestone years, the projected attainment year (2025), and one post-attainment year quantitative milestone (2028) in the 2018 $PM_{2.5}$ Plan.[242] The State establishes separate direct $PM_{2.5}$ and $NO_X$ subarea budgets for each county, or partial county (for Kern County), in the SJV.[243] CARB calculated the budgets using EMFAC2014,[244] which was, at the time, CARB's latest version of the EMFAC model for estimating emissions from on-road vehicles operating in California that had been approved by EPA at the time of Plan development, and the latest modeled vehicle miles traveled and speed distributions from the SJV MPOs from the Final 2017 Federal Transportation Improvement Programs, adopted in September 2016. The budgets reflect annual average emissions consistent with the annual averaging period of the 2012 annual $PM_{2.5}$ NAAQS and the 2018 $PM_{2.5}$ Plan's RFP demonstration.

In our 2021 Proposed Rule, the EPA noted the following: (1) 2022 and 2025 are the required budget years applicable to the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (and that the attainment year of 2025 coincided with the latter milestone year based on timing of designations); (2) the EPA had approved the budgets for the 2022 RFP milestone year in acting on the Moderate area plan and, therefore, will not be acting on them again in acting on the Serious area plan; [245] (3) the EPA is not evaluating the 2019 budgets, which would neither be used in any future conformity determinations (as the plan contains budgets for 2022 and other future years), nor required for the submitted Serious area plan; and (4) the EPA would begin the motor vehicle emissions budget adequacy and approval review processes for the 2028 post-attainment milestone year budgets only if the area were to fail to attain the standard by December 31, 2025 (the applicable Serious area attainment date if the EPA were to finalize approval of the 2018 $PM_{2.5}$ Plan's attainment demonstration).

The Plan's direct $PM_{2.5}$ budgets include tailpipe, brake wear, and tire wear emissions but do not include paved road dust, unpaved road dust, and road construction dust emissions.[246] The State did not include budgets for VOC, $SO_2$, or ammonia, consistent with its precursor demonstration that control of these precursors would not significantly contribute to attainment of the 2012 annual $PM_{2.5}$ NAAQS. The State also included a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia, $SO_2$, and VOC to support a finding of insignificance under the transportation conformity rule.[247] The State is not required to include re-entrained road dust in the $PM_{2.5}$ budgets under section 93.103(b)(3) unless the EPA or the State has made a finding that these emissions are significant, and neither the State nor the EPA has made such a finding. Nevertheless, the Plan includes a discussion of the significance/insignificance factors for re-entrained road dust and concludes that such emissions are insignificant.[248] The budgets included in the 2018 $PM_{2.5}$ Plan are shown in Table 3 of this proposed rule, which is identical to Table 9 of our 2021 Proposed Rule.

TABLE 3—MOTOR VEHICLE EMISSION BUDGETS FOR THE SAN JOAQUIN VALLEY FOR THE 2012 $PM_{2.5}$ STANDARD

[Annual average, tpd]

| County | 2022 (RFP year) [a] | | 2025 (attainment year) | |
|---|---|---|---|---|
| | $PM_{2.5}$ | $NO_X$ | $PM_{2.5}$ | $NO_X$ |
| Fresno | 0.9 | 21.2 | 0.8 | 14.3 |
| Kern | 0.8 | 19.4 | 0.8 | 12.8 |
| Kings | 0.2 | 4.1 | 0.2 | 2.7 |
| Madera | 0.2 | 3.5 | 0.2 | 2.3 |
| Merced | 0.3 | 7.6 | 0.3 | 5.0 |
| San Joaquin | 0.6 | 10.0 | 0.6 | 6.9 |
| Stanislaus | 0.4 | 8.1 | 0.4 | 5.6 |
| Tulare | 0.4 | 6.9 | 0.4 | 4.7 |

Source: 2018 $PM_{2.5}$ Plan, Appendix D, Table 3–3. Budgets are rounded to the nearest tenth of a ton.

[241] 40 CFR 93.118(f).

[242] 2018 $PM_{2.5}$ Plan, App. D, Table 3–3.

[243] 40 CFR 93.124(c) and (d).

[244] EMFAC is short for *EM*ission *FAC*tor. The EPA announced the availability of the EMFAC2014 model for use in State implementation plan development and transportation conformity in California on December 14, 2015. The EPA's approval of the EMFAC2014 emissions model for SIP and conformity purposes was effective on the date of publication of the notice in the **Federal Register**.

[245] 86 FR 67343, 67346.

[246] 2018 $PM_{2.5}$ Plan, App. D, D–122 to D–123.

[247] 40 CFR 93.109(f).

[248] 2018 $PM_{2.5}$ Plan, App. D, D–121.

[a] The EPA has already approved the 2022 RFP budgets in our final rule on the State's Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

In our 2021 Proposed Rule, we also described the State's proposed trading mechanism in the 2018 $PM_{2.5}$ Plan for transportation conformity analyses that would allow future decreases in $NO_X$ emissions from on-road mobile sources to offset any on-road increases in direct $PM_{2.5}$ emissions.

We presented our evaluation of the State's Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV and proposed to approve the 2025 budgets. We noted our preliminary review of the budgets submitted for adequacy, which preceded our proposed approval of the budgets, consistent with the EPA's general process. Based on information in the Plan, we proposed that budgets were not required for $SO_2$, VOC, and ammonia.

Based on our proposed approval of the State's RFP and attainment demonstrations, and our review of the budgets in the Plan, we proposed that the 2025 budgets for RFP and attainment were consistent with those demonstrations, were clearly identified and precisely quantified, and met all other applicable statutory and regulatory requirements including the adequacy criteria in 40 CFR 93.118(e)(4) and (5). We provided a more detailed discussion of the budgets in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD. We noted that our proposed approval of the budgets for the 2012 annual $PM_{2.5}$ NAAQS did not affect the status of the previously approved budgets for the 1997 $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS, nor the 2006 24-hour $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS.[249]

Based on our review of the State's trading mechanism for transportation conformity analyses for the 2012 annual $PM_{2.5}$ NAAQS, the EPA previously proposed to approve the trading mechanism, which would allow future decreases in $NO_X$ emissions from on-road mobile sources to offset any on-road increases in $PM_{2.5}$, using a 6.5:1 $NO_X$:$PM_{2.5}$ ratio.[250] To ensure that the trading mechanism does not affect the ability to meet the $NO_X$ budget, we noted the following: (1) the Plan provides that the $NO_X$ emission reductions available to supplement the $PM_{2.5}$ budget would only be those remaining after the $NO_X$ budget has been met; (2) the SJV MPOs would have to document clearly the calculations used in the trading when demonstrating conformity, along with any additional reductions of $NO_X$ and $PM_{2.5}$ emissions in the conformity analysis; and (3) the trading calculations must be performed prior to the final rounding to demonstrate conformity with the budgets. We summarized the technical bases for our proposed approval of the trading mechanism in the 2021 Proposed Rule and in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD.

Regarding the duration of budgets for the 2012 annual $PM_{2.5}$ NAAQS, the EPA noted that once budgets are approved, they cannot be superseded by revised budgets submitted for the same CAA purpose and the same year(s) addressed by the previously approved SIP until the EPA approves the revised budgets as a SIP revision. While CARB had requested in its letter submitting the 2018 $PM_{2.5}$ Plan that the EPA limit the duration of the budgets (*i.e.,* to allow an adequacy finding, rather than approval, of future SIP revision of budgets to replace the initial budgets),[251] CARB later clarified that since they have submitted EMFAC2021 for EPA review, they no longer request that we limit the duration of our approval.[252]

Lastly, in our 2021 Proposed Rule, the EPA proposed to disapprove the contingency measure element of the 2018 $PM_{2.5}$ Plan with respect to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS, and we are not modifying our proposed action on contingency measures in this proposed rule. Accordingly, we noted that if the EPA were to finalize the proposed disapproval of the 2012 annual $PM_{2.5}$ NAAQS Serious area contingency measure element, the area would be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan reflects adopted control measures that fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[253]

2. The EPA's Reconsidered Proposal

Based on the EPA's reconsideration and proposed disapprovals of the attainment and RFP demonstrations discussed herein, we have reconsidered our proposed approval of the Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. As discussed below, the EPA now proposes to disapprove the 2025 RFP and attainment year budgets.

As noted in section I.B of this proposed rule, we are not re-proposing any action on the Plan's precursor demonstrations for $SO_X$ and VOC (*i.e.,* we retain our proposed approval that $SO_X$ and VOC are not plan precursors for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore $SO_2$ and VOC budgets would not be required, consistent with the transportation conformity regulation (40 CFR 93.102(b)(2)(v))). However, as discussed in section II.A.3 of this proposed rule, the EPA now proposes to disapprove the State's precursor demonstration that ammonia does not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore the Plan's precursor demonstration would not address the State's obligation to consider whether ammonia budgets are necessary in the Serious area plan.

In the Plan, the State provides a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia (and $SO_2$ and VOC), which would demonstrate a finding of insignificance under the transportation conformity rule.[254] The factors typically addressed for significance include an examination of the on-road contribution of ammonia to the total emissions, and the likelihood of future motor vehicle emission controls. We note that annual average ammonia emissions from on-road mobile sources are an estimated 3.4 tpd of a total of 324.3 tpd from all sources in 2025, or about 1% of the total ammonia emissions.[255] Based on our

[249] 76 FR 69896, 69923–69924 (November 9, 2011) (final rule approving direct $PM_{2.5}$ and $NO_X$ budgets for 2012 and 2014 for the 1997 annual and 24-hour $PM_{2.5}$ NAAQS); and 85 FR 44192, 44204 (final rule approving direct $PM_{2.5}$ and $NO_X$ budgets for 2020, 2023, and 2024 for the 2006 24-hour $PM_{2.5}$ NAAQS); and 86 FR 53150, 53176–53179 (September 24, 2021) (proposed rule to approve budgets from the 2018 $PM_{2.5}$ Plan for direct $PM_{2.5}$ and $NO_X$ for 2017 and 2020 for the 1997 24-hour $PM_{2.5}$ NAAQS). We note that, following our 2021 Proposed Rule on the 2012 annual $PM_{2.5}$ NAAQS portion of the Plan, the EPA finalized approval of the 2017 and 2020 budgets for the 1997 24-hour $PM_{2.5}$ NAAQS portion of the Plan. 87 FR 4503.

[250] For example, a 1 tpd excess of direct $PM_{2.5}$ emissions from on-road mobile sources in 2025 could be offset by a 6.5 tpd reduction in $NO_X$ emissions below the $NO_X$ budget for on-road mobile sources in 2025.

[251] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX, 3.

[252] Email dated November 30, 2021, from Nesamani Kalandiyur, Manager, Transportation Analysis Section, Sustainable Transportation and Communities Division, CARB, to Karina O'Connor, EPA Region IX.

[253] 40 CFR 93.120(a)(3).

[254] For the criteria and procedures for demonstrating a finding of insignificance under the transportation conformity rule, see 40 CFR 93.109(f).

[255] 2018 $PM_{2.5}$ Plan, App. B, Table B–5.

review, and the small contribution of ammonia emissions from on-road mobile sources, the EPA agrees with the State's finding that on-road mobile source emissions of ammonia are insignificant and therefore the State is not required to include budgets for ammonia in its Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

With respect to the 2025 RFP and attainment year, the EPA proposes to disapprove the direct $PM_{2.5}$ and $NO_X$ budgets for 2025, as follows. While the 2025 budgets for RFP and attainment were clearly identified and precisely quantified, in this proposed rule the EPA proposes to disapprove the State's Serious area RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS.[256] The EPA cannot approve budgets where the underlying CAA requirements (*i.e.,* RFP and attainment) are disapproved and therefore proposes to disapprove the 2025 budgets. The budgets, when considered together with all other emission sources, cannot be consistent with the applicable requirements for RFP and attainment of the 2012 annual $PM_{2.5}$ NAAQS given the proposed disapprovals of the RFP and attainment demonstrations. Therefore, we are proposing to disapprove the motor vehicle emissions budgets because they do not meet applicable statutory and regulatory requirements, including the adequacy criteria specified in the transportation conformity rule.[257] If the EPA finalizes the disapproval, the EPA would concurrently withdraw the adequacy finding for the 2025 RFP and attainment year motor vehicle emission budgets.[258]

Lastly, given that we now propose to disapprove the Plan's RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS, rather than just the Serious area contingency measure element alone (as described in our 2021 Proposed Rule), the SJV would not be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan's control measures do not fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[259]

As a result, if the EPA finalizes our proposed disapproval of the budgets, upon the effective date of our final rule the area would be subject to a conformity freeze under 40 CFR 93.120 of the transportation conformity rule. No new transportation plan, TIP, or project may be found to conform until the State submits another control strategy implementation plan revision fulfilling the same CAA requirements, the EPA finds the budgets in the revised plan adequate or approves the budgets, the MPO makes a conformity determination for the new budgets, and the U.S. Department of Transportation makes a conformity determination.[260] In addition, only transportation projects outside of the first four years of the current conforming transportation plan and TIP or that meet the requirements of 40 CFR 93.104(f) during the resulting conformity freeze may be found to conform until California submits a new attainment and RFP plan for the 2012 annual $PM_{2.5}$ NAAQS and (1) the EPA finds the submitted budgets adequate per 40 CFR 93.118 or (2) the EPA approves the new attainment plan and conformity to the new plan is determined.[261] Furthermore, if, as a result of our final disapproval action, the EPA imposes highway sanctions under section 179(b)(1) of the Act two years from the effective date of our final rule, then the conformity status of the transportation plan and TIP will lapse on that date and no new transportation plan, TIP, or project may be found to conform until California submits a new plan for the 2012 annual $PM_{2.5}$ NAAQS, and conformity to the plan is determined.[262]

## III. Environmental Justice Considerations

Executive Order 12898 (59 FR 7629, February 16, 1994) requires that Federal agencies, to the greatest extent practicable and permitted by law, identify and address disproportionately high and adverse human health or environmental effects of their actions on minority and low-income populations. Additionally, Executive Order 13985 (86 FR 7009, January 25, 2021) directs Federal Government agencies to assess whether, and to what extent, their programs and policies perpetuate systemic barriers to opportunities and benefits for people of color and other underserved groups, and Executive Order 14008 (86 FR 7619, February 1, 2021) directs Federal agencies to develop programs, policies, and activities to address the disproportionate health, environmental, economic, and climate impacts on disadvantaged communities.

To identify environmental burdens and susceptible populations in underserved communities in the SJV nonattainment area and to better understand the context of our proposed action on the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan on these communities, we conducted a screening-level analysis using the EPA's environmental justice (EJ) screening and mapping tool (''EJSCREEN'').[263] Our screening-level analysis indicates that all eight counties in the SJV score above the national average for the EJSCREEN ''Demographic Index'' (*i.e.,* ranging from 48% in Stanislaus County to 61% in Tulare County, compared to 36% nationally).[264] The Demographic Index is the average of an area's percent minority and percent low income populations, *i.e.,* the two populations explicitly named in Executive Order 12898.[265] All eight counties also score above the national average for demographic indices of ''linguistically isolated population'' and ''population with less than high school education.''

With respect to pollution, all eight counties score at or above the 97th percentile nationally for the $PM_{2.5}$ index and seven of the eight counties in the SJV score at or above the 90th percentile nationally for the $PM_{2.5}$ EJ index, which is a combination of the Demographic Index and the $PM_{2.5}$ index. Most counties also scored above the 80th percentile for each of 11 additional EJ indices included in the EPA's EJSCREEN analysis. In addition, several

[256] See 40 CFR 93.118(e)(4)(iii).

[257] 40 CFR 93.118(e)(4).

[258] The EPA found the 2025 budgets adequate in our 2021 Proposed Rule. See also, the EPA's 2012 Annual $PM_{2.5}$ TSD, 41.

[259] 40 CFR 93.120(a)(3).

[260] 40 CFR 93.120(a)(2).

[261] Id.

[262] 40 CFR 93.120(a)(1).

[263] EJSCREEN provides a nationally consistent dataset and approach for combining environmental and demographic indicators. EJSCREEN is available at *https://www.epa.gov/ejscreen/what-ejscreen.* The EPA used EJSCREEN to obtain environmental and demographic indicators representing each of the eight counties in the San Joaquin Valley. We note that the indicators for Kern County are for the entire county. While the indicators might have slightly different numbers for the SJV portion of the county, most of the county's population is in the SJV portion, and thus the differences would be small. These indicators are included in EJSCREEN reports that are available in the rulemaking docket for this action.

[264] EPA Region IX, ''EJSCREEN Analysis for the Eight Counties of the San Joaquin Valley Nonattainment Area,'' August 2022.

[265] EJSCREEN reports environmental indicators (*e.g.,* air toxics cancer risk, Pb paint exposure, and traffic proximity and volume) and demographic indicators (*e.g.,* people of color, low income, and linguistically isolated populations). The score for a particular indicator measures how the community of interest compares with the State, the EPA region, or the national average. For example, if a given location is at the 95th percentile nationwide, this means that only 5% of the US population has a higher value than the average person in the location being analyzed. EJSCREEN also reports EJ indexes, which are combinations of a single environmental indicator with the EJSCREEN Demographic Index. For additional information about environmental and demographic indicators and EJ indexes reported by EJSCREEN, see EPA, ''EJSCREEN Environmental Justice Mapping and Screening Tool—EJSCREEN Technical Documentation,'' section 2 (September 2019).

counties scored above the 90th percentile for certain EJ indices, including, for example, the Ozone EJ Index (Fresno, Kern, Madera, Merced, and Tulare counties), the National Air Toxics Assessment (NATA) Respiratory Hazard EJ Index (Madera and Tulare counties), and the Wastewater Discharge Indicator EJ Index (Merced, San Joaquin, Stanislaus, and Tulare counties).[266]

As discussed in the EPA's EJ technical guidance, people of color and low-income populations, such as those in the SJV, often experience greater exposure and disease burdens than the general population, which can increase their susceptibility to adverse health effects from environmental stressors.[267] Underserved communities may have a compromised ability to cope with or recover from such exposures due to a range of physical, chemical, biological, social, and cultural factors.[268] The EPA is committed to environmental justice for all people, and we acknowledge that the SJV nonattainment area includes minority and low income populations that are subject to higher levels of $PM_{2.5}$ and other pollution relative to State and national averages, and that such concerns could be affected by this action.

If the EPA were to finalize the proposed disapprovals described in section II of this proposed rule, California would be required to submit a plan revision for the SJV for the 2012 annual $PM_{2.5}$ NAAQS to address the identified deficiencies. In addition, as summarized in section V of this proposed rule, such final action would trigger clocks for the SJV for offset sanctions 18 months after the final rule effective date, highway funding sanctions six months after the offset sanctions, and the obligation for the EPA to promulgate a Federal implementation plan (FIP) within two years of the final rule effective date. These obligations ensure that the identified deficiencies are resolved in an expeditious manner, consistent with the principles of environmental justice.

We note that, in developing and proposing draft regulations for governing board consideration, both CARB and the District consider the potential benefits of proposed measures for reducing health hazards to disadvantaged communities, such as diesel PM exposure near Heavy-Duty truck corridors and indoor smoke exposure from residential wood burning. There may be further opportunities to address EJ concerns through such control development and implementation.

More broadly, California law has established additional requirements for community-focused action to reduce air pollution in the State. For example, in response to California Assembly Bill 617 (2017), CARB and the District have engaged communities in the SJV, performed technical evaluations, and ultimately selected four communities (South Central Fresno, Shafter, Stockton, and Arvin/Lamont) that are in varying stages of developing and implementing community air monitoring programs and community emission reduction programs.[269] Furthermore, grant programs implemented by the local, State, and Federal authorities may serve to smooth and accelerate emission reductions of $PM_{2.5}$ and its precursor pollutants in the SJV, thereby relieving some of the cumulative burden on disadvantaged communities in the SJV nonattainment area.[270]

## IV. Title VI of the Civil Rights Act

As noted in section I.C of this proposed rule, the EPA received a comment letter dated January 28, 2022 (the Public Justice Comment Letter), on the 2021 Proposed Rule from a coalition of 13 organizations.

The commenters urge the EPA to disapprove the Serious area plan ''because EPA has failed to require CARB/SJV to provide necessary assurances that the State implementation plan complies with Title VI of the Civil Rights Act of 1964. The on-going environmental justice and air pollution crisis demand EPA reverse course and disapprove the 2012 plan.'' [271] To support this argument, the commenters provide information regarding the racial demographics of the SJV, the potential for disparate impacts from exposure to $PM_{2.5}$, and specific aspects of the SJV $PM_{2.5}$ Plan that the commenters believe result in disparate impacts. The commenters point to past precedent in which the EPA has considered compliance with Title VI of the Civil Rights Act (Title VI) in the SIP context through CAA section 110(a)(2)(E). The commenters also note that thus far California has provided no ''demonstration'' that the Serious area plan does not cause or exacerbate disparate impacts on affected communities in the SJV. Thus, the commenters assert that the EPA must disapprove the Serious area plan because the State did not provide ''required assurances'' of compliance with Title VI.

At this time, the EPA has not issued any guidance or regulations concerning what might be required for purposes of CAA section 110(a)(2)(E) as it regards Title VI. The EPA has addressed other aspects of section 110(a)(2)(E) in the context of infrastructure SIP submissions in its September 2013 ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2).'' Similarly, EPA regulations only address other aspects of section 110(a)(2)(E) in 40 CFR Sections 51.230–232.

### A. Background on CAA Section 110(a)(2)(E)

For purposes of background, section 110(a)(2)(E) of the CAA, in relevant part and with emphasis added, reads as follows:

> (2) Each implementation plan submitted by a State under this chapter shall be adopted by the State after reasonable notice and public hearing. Each such plan shall—. . .
>
> (E) provide (i) *necessary assurances* that the State (or, except where the Administrator deems inappropriate, the general purpose local government or governments, or a regional agency designated by the State or general purpose local governments for such purpose) will have adequate personnel, funding, and authority under State (and, as appropriate, local) law to carry out such implementation plan *(and is not prohibited by any provision of Federal or State law from carrying out such implementation plan or portion thereof),* (ii) requirements that the State comply with the requirements respecting State boards under section 7428 of this title, and (iii) necessary assurances that, where the State has relied on a local or regional government, agency, or instrumentality for the implementation of any plan provision, the State has responsibility for ensuring adequate implementation of such plan provision.[272]

[266] Notably, Tulare County scores above the 90th percentile on six of the 12 EJ indices in the EPA's EJSCREEN analysis, including the $PM_{2.5}$ EJ Index, which is the highest count among all SJV counties.

[267] EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' section 4 (June 2016).

[268] Id. at section 4.1.

[269] For further information, see, *e.g.,* SJVUAPCD, ''Item Number 9: Receive Progress Reports on AB617 Community Emission Reduction Program Implementation,'' November 18, 2021.

[270] For example, through the EPA's Targeted Airshed Grant program, the District has competed for, and the EPA has granted 13 awards to the District from 2015 through 2021, totaling $77.4 million, to replace older, dirtier woodstoves, agricultural equipment, heavy-duty trucks and yard trucks, and agricultural nut harvesters with cleaner equipment. A list of the Targeted Airshed Grants the EPA awarded in fiscal years 2015–2020 is accessible online at *https://www.epa.gov/air-quality-implementation-plans/targeted-airshed-grant-recipients.* These EPA grants support projects to reduce emissions in areas facing the highest levels of ground-level ozone and $PM_{2.5}$.

[271] Public Justice Comment Letter, 2.

[272] 42 U.S.C. Section 7410(a)(2)(E) (emphasis added).

The EPA has previously addressed CAA section 110(a)(2)(E)(i), Title VI, and necessary assurances in a 2012 action on a nonattainment plan SIP submission from California for purposes of the ozone NAAQS.[273] Comments submitted on the EPA's April 24, 2012 proposed action contended that the SIP submission was not in compliance with CAA section 110(a)(2)(E) because of alleged violations of Title VI related to the regulation of pesticides as precursors to ozone (as volatile organic compounds). To evaluate the commenter's concerns, the EPA sought additional necessary assurances from the State concerning its regulation of pesticides. California submitted additional information to the EPA concerning the State's activities that were part of the resolution of a Title VI complaint, and additional information concerning the State's regulation of pesticides. California submitted this information to provide ''necessary assurances'' to the EPA that implementation of the requirements of the SIP submission would not violate Title VI. The EPA accepted this information as providing adequate necessary assurances for purposes of section 110(a)(2)(E) and did not require the State to make any substantive changes to support approval of the SIP revision.

Commenters in the 2012 action asserted that California had not provided sufficient necessary assurances. In the response to comments in the 2012 action, the EPA explained that ''Section 110(a)(2)(E), however, does not require a State to 'demonstrate' it is not prohibited by Federal or State law from implementing its proposed SIP revision. Rather, this section requires a State to provide 'necessary assurances' of this.'' [274] The EPA further explained,

> Courts have given EPA ample discretion in deciding what assurances are ''necessary'' and have held that a general assurance or certification is sufficient. (''EPA is entitled to rely on a state's certification unless it is clear that the SIP violates state law and proof thereof * * * is presented to EPA.'' *BCCA Appeal Group* v. *EPA,* 355 F.3d 817, 830 fn 11 (5th Cir. 2003)).[275]

The EPA received a petition for review (from groups overlapping with the groups that sent the Public Justice Comment Letter) of the EPA's October 26, 2012 final action which was reviewed and ultimately decided in EPA's favor by the Ninth Circuit Court of Appeals.[276] The Court used an arbitrary and capricious standard of review to evaluate the EPA's conclusion that the State had provided adequate ''necessary assurances'' that implementation of the SIP is not prohibited by Federal law—specifically, Title VI of the Federal Civil Rights Act of 1964—per the language of section 110(a)(2)(E). The Ninth Circuit found that the EPA fulfilled its duty to provide a reasoned judgment because its determination was cogently explained and supported by the record. In dismissing the petition, the Court explained that ''[t]he EPA has a duty to provide a reasoned judgment as to whether the State has provided 'necessary assurances,' but what assurances are 'necessary' is left to the EPA's discretion.'' [277]

*B. Background on Title VI of the Civil Rights Act of 1964*

For purposes of background context, Title VI prohibits recipients of Federal financial assistance from discriminating on the basis of race, color, or national origin. Under the EPA's nondiscrimination regulations, which implement Title VI and other civil rights laws,[278] recipients of EPA financial assistance are prohibited from taking actions in their programs or activities that are intentionally discriminatory and/or have an unjustified disparate impact.[279] This includes policies, criteria or methods of administering programs that are neutral on their face but have the effect of discriminating.[280] Under the EPA's regulation, recipients of EPA financial assistance are also required to have in place certain procedural safeguards, including grievance procedures that assure the prompt and fair resolution of external discrimination complaints.[281]

The EPA carries out its mandate to ensure that recipients of EPA financial assistance comply with their nondiscrimination obligations by investigating administrative complaints filed with the EPA alleging discrimination prohibited by Title VI and the other civil rights laws; [282] initiating affirmative compliance reviews; [283] and providing technical assistance to recipients to assist them in meeting their Title VI obligations. In the current matter being addressed in this action, no Title VI complaint was filed regarding CARB or the District.[284] Also, the EPA (through the External Civil Rights Compliance Office or ECRCO) has not initiated and is not currently conducting a compliance review of either CARB or SJVUAPCD.

*C. Comments Received on 2021 Proposed Rule*

The commenters raise the issue of compliance with section 110(a)(2)(E) with respect to Title VI. The commenters contend that the SIP submission for the SJV is not in compliance with CAA section 110(a)(2)(E) because California has not provided necessary assurances to ensure that implementation of the SIP is in compliance with Title VI. The commenters did not submit these specific comments to CARB or the SJVUAPCD during the State's development and adoption process of the proposed SIP revisions that are currently at issue. The commenters are not required to have done so to raise this issue with the EPA now, but as a result, the SIP submission to the EPA does not include any CARB or District response concerning this specific issue. In addition, the SIP submission does not include specifically identified necessary assurances per section 110(a)(2)(E) provided by the State.

At the outset, the EPA acknowledges the statements in the comment letter that the SJV area has historically been designated as nonattainment for the $PM_{2.5}$ NAAQS and that the SJV area includes higher representation of persons of color compared to the State average. Although in this action the EPA is not proposing to disapprove on the basis of CAA section 110(a)(2)(E), if the EPA disapproves the Serious area plan as proposed today, California would need to submit a revised Serious area plan for the SJV. The EPA expects that any such revision would comply with the requirements of section 110(a)(2)(E) and that CARB and the District will engage with the community through notice and comment during the SIP

[273] 77 FR 65294 (October 26, 2012) (final rule); 77 FR 24441 (April 24, 2012) (proposed rule).

[274] 77 FR 65294, 65302, column 2.

[275] Id.

[276] *El Comité Para El Bienstar de Earlimart et al. (El Comité)* v. *EPA,* 786 F.3d 688 (9th Cir. 2015).

[277] 786 F.3d at 700.

[278] 40 CFR part 7 and part 5.

[279] 40 CFR Sections 7.30 and 7.35.

[280] 40 CFR Section 7.35(b).

[281] 40 CFR Section 7.90.

[282] 40 CFR Section 7.120.

[283] 40 CFR Section 7.115.

[284] The EPA's External Civil Rights Compliance Office (ECRCO) contacted Mr. Brent Newell, signatory to the Public Justice Comment Letter, to see whether the commenters intended to file a Title VI administrative complaint with the EPA. In response, the commenters stated, ''[t]he comments submitted were neither intended nor styled as a Title VI complaint. The comments raise significant issues with respect to EPA's proposed approval, including the section 110(a)(2)(E) issues and EPA's authority and duty to enforce Title VI, and we expect EPA to respond to all of the issues in the final action/response to comments.'' Email exchange dated February 8, 2022, between Brent Newell, Public Justice and Lilian Dorka, Director, External Civil Rights Compliance Office, EPA Office of General Counsel.

development process for its revised Serious area plan prior to submitting a revised SIP to the EPA, and specifically with respect to necessary assurances relative to Title VI. The new SIP development process provides an important opportunity for CARB and the District to identify potential adverse disparate impacts on the basis of race, color, or national origin from its revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS and address them as appropriate.

The EPA acknowledges that it has not issued national guidance or regulations concerning implementation of section 110(a)(2)(E) as it pertains to consideration of Title VI and disparate impacts on the basis of race, color, or national origin in the context of the SIP program. Such guidance is forthcoming and will address CAA section 110(a)(2)(E)'s necessary assurance requirements as they relate to Title VI. In the interim, CARB and the District may find existing EPA and DOJ Title VI and environmental justice resources useful, even though these documents do not relate specifically to CAA section 110(a)(2)(E).[285] Additionally, the EPA's ECRCO is available to provide technical assistance regarding Title VI compliance to CARB and/or the District as they develop the revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

## V. Summary of Proposed Actions and Request for Public Comment

For the reasons discussed in this proposed rule, under CAA section 110(k)(3), the EPA proposes to disapprove, as a revision to the California SIP, the following portions of the SJV $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS to address the CAA's Serious area planning requirements in the SJV nonattainment area:

(1) the demonstration that BACM, including BACT, for the control of ammonia emission sources and for the control of $NO_X$ and direct $PM_{2.5}$ building heating emission sources will be implemented no later than 4 years after the area was reclassified (CAA section 189(b)(1)(B) and 40 CFR 51.1010(a));

(2) the demonstration that the Plan provides for attainment as expeditiously as practicable but no later than December 31, 2025 (CAA sections 188(c)(2) and 189(b)(1)(A) and 40 CFR 51.1011(b));

(3) plan provisions that require RFP toward attainment by the applicable date (CAA section 172(c)(2) and 40 CFR 51.1012(a));

(4) quantitative milestones that are to be achieved every three years until the area is redesignated attainment and that demonstrate RFP toward attainment by the applicable attainment date (CAA section 189(c) and 40 CFR 51.1013(a)(2)(i)); and

(5) motor vehicle emissions budgets for 2025 as shown in Table 3 of this proposed rule (CAA section 176(c) and 40 CFR part 93, subpart A).

We are also proposing to disapprove the State's precursor demonstration for ammonia. Our proposed action on the emissions inventory and contingency measure elements remains unchanged from our 2021 Proposed Rule.

If we finalize the proposed disapprovals for BACM, the attainment demonstration, RFP, quantitative milestones, or motor vehicle emission budgets, the offset sanction in CAA section 179(b)(2) would apply in the SJV 18 months after the effective date of a final disapproval, and the highway funding sanctions in CAA section 179(b)(1) would apply in the area six months after the offset sanction is imposed.[286] Neither sanction will be imposed under the CAA if the State submits and we approve, prior to the implementation of the sanctions, a SIP revision that corrects the deficiencies that we identify in our final action. The EPA intends to work with CARB and the SJVUAPCD to correct the deficiencies in a timely manner.

In addition to the sanctions, CAA section 110(c)(1) provides that the EPA must promulgate a Federal implementation plan (FIP) addressing any disapproved elements of an attainment plan two years after the effective date of disapproval unless the State submits, and the EPA approves, a SIP submission that cures the disapproved elements.

Furthermore, if we take final action disapproving the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, a conformity freeze will take effect upon the effective date of any final disapproval (usually 30 days after publication of the final action in the **Federal Register**). A conformity freeze means that only projects in the first four years of the most recent RTP and TIP can proceed. During a freeze, no new RTPs, TIPs, or RTP/TIP amendments can be found to conform.[287]

We will accept comments from the public on these proposals for the next 45 days. The deadline and instructions for submission of comments are provided in the **DATES** and **ADDRESSES** sections at the beginning of this proposed rule.

## VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

### *A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review*

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

### *B. Paperwork Reduction Act (PRA)*

This action does not impose an information collection burden under the PRA, because this proposed SIP disapproval, if finalized, will not in-and-of itself create any new information collection burdens, but will simply disapprove certain State requirements for inclusion in the SIP.

### *C. Regulatory Flexibility Act (RFA)*

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new requirements but will simply disapprove certain State requirements for inclusion in the SIP.

### *D. Unfunded Mandates Reform Act (UMRA)*

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action proposes to disapprove certain pre-existing requirements under State or local law, and imposes no new requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

### *E. Executive Order 13132: Federalism*

This action does not have federalism implications. It will not have substantial

[285] See ECRCO's Toolkit Chapter I at: *https://www.epa.gov/sites/default/files/2017-01/documents/toolkit-chapter1-transmittal_letter-faqs.pdf,* January 18, 2017, and Department of Justice ''Title VI Legal Manual (Updated)'' at: *https://www.justice.gov/crt/fcs/T6Manual6.* See also, *e.g.,* EPA, ''Guidance on Considering Environmental Justice During the Development of Regulatory Actions,'' (May 2015), and EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' (June 2016).

[286] 40 CFR 52.31.

[287] See 40 CFR 93.120(a).

direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

*F. Executive Order 13175: Coordination With Indian Tribal Governments*

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP revision that the EPA is proposing to partially disapprove would not apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

*G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks*

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because this proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new regulations, but will simply disapprove certain State requirements for inclusion in the SIP.

*H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use*

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

*I. National Technology Transfer and Advancement Act (NTTAA)*

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

*J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population*

Executive Order 12898 (59 FR 7629 (February 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA's evaluation of this issue is contained in the section of the preamble titled ''Environmental Justice Considerations.''

**List of Subjects 40 CFR Part 52**

Environmental protection, Air pollution control, Ammonia, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

**Authority:** 42 U.S.C. 7401 *et seq.*

Dated: September 28, 2022.

**Martha Guzman Aceves,**

*Regional Administrator, Region IX.*

[FR Doc. 2022–21492 Filed 10–4–22; 8:45 am]

BILLING CODE 6560–50–P

# ATTACHMENT H

# Health and Environmental Effects of Particulate Matter (PM)

## Health Effects

The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease
- nonfatal heart attacks
- irregular heartbeat
- aggravated asthma <https://epa.gov/asthma>
- decreased lung function
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children, and older adults are the most likely to be affected by particle pollution exposure.

- AirNow <https://airnow.gov/> can help you monitor air quality near you, and protect yourself and your family from elevated PM levels.

# Environmental Effects

## Visibility impairment

Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. Learn more about visibility and haze <https://epa.gov/visibility>

## Environmental damage

Particles can be carried over long distances by wind and then settle on ground or water. Depending on their chemical composition, the effects of this settling may include:

- making lakes and streams acidic
- changing the nutrient balance in coastal waters and large river basins
- depleting the nutrients in soil
- damaging sensitive forests and farm crops
- affecting the diversity of ecosystems
- contributing to acid rain effects <https://epa.gov/acidrain/effects-acid-rain>.

## Materials damage

PM can stain and damage stone and other materials, including culturally important objects such as statues and monuments. Some of these effects are related to acid rain effects on materials <https://epa.gov/acidrain/effects-acid-rain#materials>.

# Further Reading

Particle Pollution and Your Health (PDF)(2 pp, 320 K, About PDF <https://epa.gov/home/pdf-files>): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health <https://www.airnow.gov/air-quality-and-health/fires-and-your-health/>: It is important to limit your exposure to smoke -- especially if you may be susceptible.

EPA research on airborne particulate matter <https://epa.gov/air-research>: EPA supports research that provides the critical science on PM and other air pollutants to develop and implement Clean Air Act regulations that protect the quality of the air we breathe.

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PM Home <https://epa.gov/pm-pollution>

- Particulate Matter (PM) Basics <https://epa.gov/pm-pollution/particulate-matter-pm-basics>
- **Health and Environmental Effects**
- Setting and Reviewing PM Standards <https://epa.gov/pm-pollution/setting-and-reviewing-standards-control-particulate-matter-pm-pollution>
- PM Standards Regulatory Actions <https://epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm>
- Implementing PM Standards <https://epa.gov/pm-pollution/applying-or-implementing-particulate-matter-pm-standards>
- PM Implementation Regulatory Actions <https://epa.gov/pm-pollution/particulate-matter-pm-implementation-regulatory-actions>
- SIP Checklist Guide <https://epa.gov/pm-pollution/pm-state-implementation-plan-sip-checklist-guide>
- PM SIP Training Presentations <https://epa.gov/pm-pollution/pm-naaqs-implementation-training-and-assistance-state-and-local-air-agencies>
- PM Data and SIP Status Reports <https://epa.gov/pm-pollution/technical-data-and-reports-particulate-matter-pm-measurements-and-sip-status>
- Other Criteria Air Pollutants <https://epa.gov/criteria-air-pollutants>

Contact Us <https://epa.gov/pm-pollution/forms/contact-us-about-particulate-matter-pm-pollution> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON AUGUST 23, 2023

# Discover.

### Accessibility Statement
<https://epa.gov/accessibility/epa-accessibility-statement>

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<https://epa.gov/utilities/wwwepagov-snapshots>

## Grants

<https://epa.gov/grants>

## No FEAR Act Data

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## Plain Writing

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# Follow.

# ATTACHMENT I

# Understanding Global Warming Potentials

Greenhouse gases (GHGs) warm the Earth by absorbing energy and slowing the rate at which the energy escapes to space; they act like a blanket insulating the Earth. Different GHGs can have different effects on the Earth's warming. Two key ways in which these gases differ from each other are their ability to absorb energy (their "radiative efficiency"), and how long they stay in the atmosphere (also known as their "lifetime").

The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide ($CO_2$). The larger the GWP, the more that a given gas warms the Earth compared to $CO_2$ over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases.

- $CO_2$, by definition, has a GWP of 1 regardless of the time period used, because it is the gas being used as the reference. $CO_2$ remains in the climate system for a very long time: $CO_2$ emissions cause increases in atmospheric concentrations of $CO_2$ that will last thousands of years.
- Methane ($CH_4$) is estimated to have a GWP of 27-30 over 100 years. $CH_4$ emitted today lasts about a decade on average, which is much less time than $CO_2$. But $CH_4$ also absorbs much more energy than $CO_2$. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The $CH_4$ GWP also accounts for some indirect effects, such as the fact that $CH_4$ is a precursor to ozone, and ozone is itself a GHG.
- Nitrous Oxide ($N_2O$) has a GWP 273 times that of $CO_2$ for a 100-year timescale. $N_2O$ emitted today remains in the atmosphere for more than 100 years, on average. (Learn why EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks uses a different value.)

- Chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$) are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than $CO_2$. (The GWPs for these gases can be in the thousands or tens of thousands.)

# Frequently Asked Questions

## Why do GWPs change over time?

> EPA and other organizations will update the GWP values they use occasionally. This change can be due to updated scientific estimates of the energy absorption or lifetime of the gases or to changing atmospheric concentrations of GHGs that result in a change in the energy absorption of 1 additional ton of a gas relative to another.

## Why are GWPs presented as ranges?

> In the most recent report by the Intergovernmental Panel on Climate Change (IPCC), multiple methods of calculating GWPs were presented based on how to account for the influence of future warming on the carbon cycle. For this Web page, we are presenting the range of the lowest to the highest values listed by the IPCC.

## What GWP estimates does EPA use for GHG emissions accounting, such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and the Greenhouse Gas Reporting Program?

The EPA considers the GWP estimates presented in the most recent IPCC scientific assessment to reflect the state of the science. In science communications, the EPA will refer to the most recent GWPs. The GWPs listed above are from the IPCC's Sixth Assessment Report, published in 2021.

The EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC guidelines now require the use of the GWP values from the IPCC's Fifth Assessment Report (AR5), published in 2013. The Inventory also presents emissions by mass, so that $CO_2$ equivalents can be calculated using any GWPs, and emission totals using more recent IPCC values are presented in the annexes of the Inventory report for informational purposes.

The data collected by EPA's Greenhouse Gas Reporting Program is generally reported in mass units of greenhouse gas and is used in the Inventory. The Reporting Program, generally uses GWP values from the AR4 to determine whether facilities exceed reporting thresholds and to publish data in $CO_2$ equivalent values. The Reporting Program collects data about some industrial gases that do not have GWPs listed in the AR4; for these gases, the Reporting Program uses GWP values from other sources, such as the AR5.

EPA's $CH_4$ reduction voluntary programs also use $CH_4$ GWPs from the AR5 report for calculating $CH_4$ emissions reductions through energy recovery projects, for consistency with the national emissions presented in the Inventory.

## Are there alternatives to the 100-year GWP for comparing GHGs?

The United States primarily uses the 100-year GWP as a measure of the relative impact of different GHGs. However, the scientific community has developed a number of other metrics that could be used for comparing one GHG to another. These metrics may differ based on timeframe, the climate endpoint measured, or the method of calculation.

For example, the 20-year GWP is sometimes used as an alternative to the 100-year GWP. Just like the 100-year GWP is based on the energy absorbed by a gas over 100 years, the 20-year GWP is based on the energy absorbed over 20 years. This 20-year GWP prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur. Because all GWPs are calculated relative to $CO_2$, GWPs based on a shorter timeframe will be larger for gases with lifetimes shorter than that of $CO_2$, and smaller for gases with lifetimes longer than $CO_2$. For example, for $CH_4$, which has a short lifetime, the 100-year GWP of 27–30 is much less than the 20-year GWP of 81–83. For $CF_4$, with a lifetime of 50,000 years, the 100-year GWP of 7380 is larger than the 20-year GWP of 5300.

Another alternate metric is the Global Temperature Potential (GTP). While the GWP is a measure of the heat absorbed over a given time period due to emissions of a gas, the GTP is a measure of the temperature change at the end of that time period (again, relative to $CO_2$).The calculation of the GTP is more complicated than that for the GWP, as it requires modeling how much the climate system responds to increased concentrations of GHGs (the climate sensitivity) and how quickly the system responds (based in part on how the ocean absorbs heat).

GHG Emissions and Removals Home <https://epa.gov/ghgemissions>

Overview of Greenhouse Gases <https://epa.gov/ghgemissions/overview-greenhouse-gases>

Sources of GHG Emissions and Removals <https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions>

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- Facility-Level Emissions <https://epa.gov/ghgreporting>
- Gridded Methane Emissions <https://epa.gov/ghgemissions/us-gridded-methane-emissions>
- Carbon Footprint Calculator <https://epa.gov/ghgemissions/household-carbon-footprint-calculator>
- GHG Equivalencies Calculator <http://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>
- Capacity Building for GHG Inventories <https://epa.gov/ghgemissions/capacity-building-national-greenhouse-gas-inventories>

Contact Us <https://epa.gov/ghgemissions/forms/contact-us-about-greenhouse-gas-emissions> to ask a question, provide feedback, or report a problem.

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# ATTACHMENT J

# Aura

## Atmospheric Chemistry


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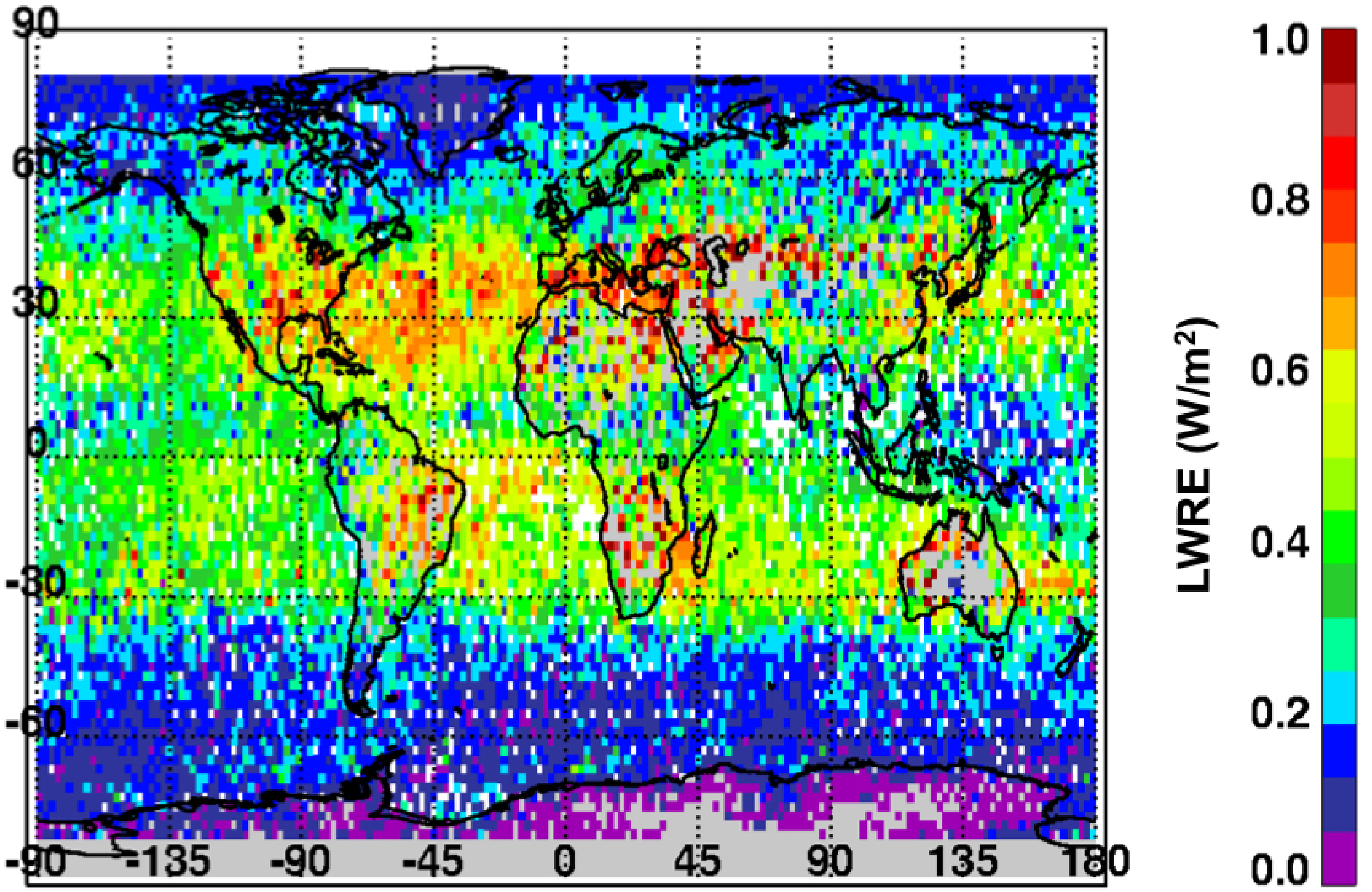
# The greenhouse effect of tropospheric ozone

**Tropospheric ozone ($O_3$) is the third most important anthropogenic greenhouse gas after carbon dioxide ($CO_2$) and methane ($CH_4$). Ozone absorbs infrared radiation (heat) from the Earth's surface, reducing the amount of radiation that escapes to space.**

This map shows the longwave radiative effect (LWRE) of infrared radiation absorbed by tropospheric ozone in Watts/meter^2 as estimated from Aura's Tropospheric Emission Spectrometer (TES) top-of- atmosphere (TOA) observations. Data are averaged for August 2006 and include both clear-sky and cloudy scenes. Areas with no data are indicated in white over oceans and grey over land.

Higher values of trapped infrared radiation are caused by lofted ozone pollution in the northern mid-latitudes and from sources of biomass burning in the southern hemisphere.

**This map shows the longwave radiative effect of infrared radiation absorbed by tropospheric ozone as estimated from TES top-of-atmosphere observations.**

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*April 2011*

## Contact

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Web Curator : Jennifer Brill

# ATTACHMENT K

Last Updated 2/9/2024 Total Number of Applications (2.0) or Pathways (3.0) 2243

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1356 | Tier 1 | 2.0 | Fuel Producer: Adecoagro Brasil Participacoes (4192) Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS211 | 46.32 | 12/20/2016 | None | Ethanol | Adecoagro Brasil Participacoes (4192) | Adecoagro Vale do Ivinhema Ltda (70496) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1078 | Tier 1 | 2.0 | Producer: BIOSEV S.A. (3869) Facility Name: Usina Cresciumal (71068). Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export. | Brazil | Molasses | Ethanol | None | None | ETHM221 | 46.34 | 12/20/2016 | None | Ethanol | BIOSEV SA (3869) | Usina Cresciumal (71068) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export | None | Retired |
| T1R-1008 | Tier 1 | 2.0 | Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Tallow; Biodiesel Produced in Canada | Ontario, Canada | Tallow | Biodiesel | BIOD023 | 46.36 | BDT200L | 34.97 | 6/30/2016 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | North American Tallow; Biodiesel Produced in Canada | None | Retired |
| T1R-1009 | Tier 1 | 2.0 | Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Soybean; Biodiesel Produced in Canada | Ontario, Canada | Soybean | Biodiesel | BIOD024 | 88.59 | BDS200L | 56.03 | 6/30/2016 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | North American Soybean; Biodiesel Produced in Canada | None | Retired |
| T1R-1010 | Tier 1 | 2.0 | Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Canola; Biodiesel Produced in Canada | Ontario, Canada | Canola | Biodiesel | BIOD026 | 67.32 | BDCA200L | 57.39 | 6/30/2016 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | North American Canola; Biodiesel Produced in Canada | None | Retired |
| T1R-1012 | Tier 1 | 2.0 | Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada | Ontario, Canada | North American Corn Oil from Wet DGS | Biodiesel | BIOD030 | 35.23 | BDC200L | 32.80 | 6/30/2016 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada | None | Retired |
| T1N-1069 | Tier 1 | 2.0 | Fuel Producer: Usina Sao Domingos Acucar e Alcool S.A. (4252) Facility Name: Usina Sao Domingos Acucar e Alcool SA (70533): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | Brazil | Sugarcane | Ethanol | None | None | ETHS234 | 46.44 | 5/19/2017 | None | Ethanol | Usina Sao Domingos Acucar e Alcool SA (4252) | Usina Sao Domingos Acucar e Alcool SA (70533) | Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1141 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Santa Helena (70558): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | Brazil | Molasses | Ethanol | None | None | ETHM230 | 46.44 | 5/19/2017 | None | Ethanol | Raízen Energia S/A (3805) | Santa Helena (70558) | Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1460 | Tier 1 | 2.0 | Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Volta Grande (70371). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS214 | 46.49 | 12/20/2016 | None | Ethanol | Usina Delta SA (3852) | Usina Delta S/A Unidade Volta Grande (70371) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1073 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Vale do Rosário (70440). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM200 | 46.52 | 3/31/2016 | None | Ethanol | BIOSEV SA (3869) | Usina Vale do Rosário (70440) | Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1392 | Tier 1 | 2.0 | Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Usina São Martinho S.A. (70373). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS219 | 46.61 | 12/20/2016 | None | Ethanol | Usina São Martinho SA (3867) | Usina São Martinho SA (70373) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1040 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Australian Rendered Tallow to Renewable Diesel. Renewable Diesel Produced in Singapore. | Singapore | Australian Tallow | Renewable Diesel | RNWD004 | 33.46 | RDT200L | 36.83 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Australian Rendered Tallow to Renewable Diesel; Renewable Diesel Produced in Singapore | None | Retired |
| T1R-1041 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). North American Rendered Tallow to Renewable Diesel Produced in Singapore. | Singapore | North American Tallow | Renewable Diesel | RNWD005 | 49.69 | RDT201L | 34.19 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | North American Rendered Tallow to Renewable Diesel Produced in Singapore | None | Retired |
| T1R-1042 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). South East Asia Fish Oil to Renewable Diesel Produced in Singapore. | Singapore | South East Asian Fish Oil | Renewable Diesel | RNWD006 | 30.48 | RDF200L | 33.08 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | South East Asia Fish Oil to Renewable Diesel Produced in Singapore | None | Retired |
| T1R-1043 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327): New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore | Singapore | Tallow | Renewable Diesel | RNWD007 | 36.57 | RDT203L | 34.81 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore | None | Retired |
| T1R-1045 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Midwest Corn Oil to Renewable Diesel Produced in Singapore. | Singapore | Midwest Corn Oil from Wet DGS | Renewable Diesel | RNWD026 | 39.13 | RDC200L | 37.39 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Midwest Corn Oil to Renewable Diesel Produced in Singapore | None | Retired |
| T1R-1046 | Tier 1 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore. | Singapore | Global Used Cooking Oil | Renewable Diesel | RNWD027 | 30.72 | RDU201L | 25.61 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore | None | Retired |
| T1N-1400 | Tier 1 | 2.0 | Fuel Producer: Branco Peres Acucar e Alcool SA (5985) Facility Name: Branco Peres Acucar e Alcool SA (71077): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS210 | 46.71 | 12/20/2016 | None | Ethanol | Branco Peres Acucar e Alcool SA (5985) | Branco Peres Acucar e Alcool SA (71077) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1058 | Tier 1 | 2.0 | Fuel Producer: Consolidated Biofuels Ltd. (3919) Facility Name: Consolidated Biofuels Ltd. (80304): North American low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Canada | Canada | Used Cooking Oil | Biodiesel | BIOD029 | 21.34 | BDU211L | 20.38 | 6/30/2016 | None | Biodiesel | Consolidated Biofuels Ltd (3919) | Consolidated Biofuels Ltd (80304) | North American lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Canada | None | Retired |
| T1N-1391 | Tier 1 | 2.0 | Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UNP) (70527). Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS218 | 46.72 | 12/20/2016 | None | Ethanol | Noble Brasil SA (4232) | Noble Brasil S/A NBSA (UNP)(70527) | Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1393 | Tier 1 | 2.0 | Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Sao Martinho S/A (70479). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS213 | 46.80 | 12/20/2016 | None | Ethanol | Usina São Martinho SA (3867) | Sao Martinho S/A (70479) | Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1062 | Tier 1 | 2.0 | Fuel Producer: Noble Brasil S.A. (4232) Facility Name: NG Bioenergia S/A - Potirendaba (71036). Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS212 | 46.83 | 9/1/2016 | None | Ethanol | Noble Brasil SA (4232) | NG Bioenergia S/A Potirendaba (71036) | Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1R-1093 | Tier 1 | 2.0 | Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): North American Used Cooking Oil (UCO); Biodiesel Produced in Arkansas | Arkansas | Used Cooking Oil | Biodiesel | BIOD027 | 23.81 | BDU207L | 24.36 | 6/30/2016 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | North American Used Cooking Oil (UCO)Biodiesel Produced in Arkansas | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1161 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG on-site; fuel dispensed on-site | California | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF246 | 9.97 | 6/22/2017 | Pathway Details (PDF) | Bio-CNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG onsite; fuel dispensed onsite | None | Retired |
| T1R-1124 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | Kansas | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF230L | 45.31 | CNGLF230LR | 50.80 | 9/30/2016 | Previous Tier 1 CNG030; 32.92 | Bio-CNG | Clean Energy (5481) | EIF KC Landfill Gas LLC (71155) | Kansas City landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1101 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Michigan | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF200L | 48.65 | LNGLF200LR | 54.14 | 9/30/2016 | Previous Tier 1 LNG025; 30.12 | Bio-LNG | Clean Energy (5481) | Westside Gas Producers LLC (71151) | Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T2N-1163 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Bay Area by Truck | California | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF247 | 10.32 | 6/22/2017 | Pathway Details (PDF) | Bio-CNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Bay Area by Truck | None | Retired |
| T1R-1104 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Ohio | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF201L | 44.78 | LNGLF201LR | 50.27 | 9/30/2016 | Previous Tier 1 LNG020; 25.5 | Bio-LNG | Clean Energy (5481) | Pinnacle Gas Producers, LLC (71153) | Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1R-1103 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA | Ohio | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF224L | 50.52 | CNGLF224LR | 56.01 | 9/30/2016 | Previous Tier 1 CNG023; 27.62 | Bio-CNG | Clean Energy (5481) | Pinnacle Gas Producers, LLC (71153) | Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA | None | Retired |
| T1R-1106 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Tennessee | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF202L | 54.57 | LNGLF202LR | 60.06 | 9/30/2016 | Previous Tier 1 LNG028; 43.83 | Bio-LNG | Clean Energy (5481) | CERF Shelby LLC (71163) | CERF Shelby landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T2N-1165 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Southern California by Truck | California | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF248 | 13.29 | 6/22/2017 | Pathway Details (PDF) | Bio-CNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Southern California by Truck | None | Retired |
| T1R-1111 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; re-gasified and compressed to CNG | Texas | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF227L | 48.41 | CNGLF227LR | 53.90 | 9/30/2016 | Previous Tier 1 CNG017; 35.11 | Bio-CNG | Clean Energy (5481) | Dallas Clean Energy McCommas Bluff (71009) | Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; regasified and compressed to CNG | None | Retired |
| T1R-1109 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | New York | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF203L | 53.61 | LNGLF203LR | 59.10 | 9/30/2016 | Previous Tier 1 LNG023; 32.03 | Bio-LNG | Clean Energy (5481) | Seneca Energy II, LLC (71156) | New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1N-1656 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154) Facility Name: East Texas Renewables (F2942): Greenwood Farms landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)** | Texas | Landfill Gas | Compressed Natural Gas | None | None | CNGLF252 | 38.62 | 6/27/2017 | None | Bio-CNG | Shell Energy North America (6154) | East Texas Renewables (F2942) | Greenwood Farms landfill gas (TX) to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional) | None | Retired |
| T1N-1383 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California. | Texas | Landfill Gas - L-CNG | Compressed Natural Gas | None | None | CNGLF222 | 48.91 | 9/30/2016 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | Needle Mountain LNG PLant (95116) | Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1112 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA | Texas | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF204L | 45.26 | LNGLF204LR | 50.75 | 9/30/2016 | Previous Tier 1 LNG018; 32.99 | Bio-LNG | Clean Energy (5481) | Dallas Clean Energy McCommas Bluff (71009) | Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA | None | Retired |
| T1N-1541 | Tier 1 | 2.0 | Fuel Producer: Athens Services (A431) Facility Name: La Puente (V4048). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional) | Louisiana | Landfill Gas | Compressed Natural Gas | CNGLF239 | 39.46 | CNGLF239R | 43.44 | 2/6/2019 | None | Bio-CNG | Athens Services (A431) | La Puente (V4048) | River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional) | None | Retired |
| T1R-1224 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | Montana | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF231L | 49.9 | CNGLF231LR | 55.39 | 9/30/2016 | Previous Tier 1 CNG058; 51.88 | Bio-CNG | Clean Energy (5481) | MontanaDakota Utilities Billings Regional Landfill (71193) | Montana landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1115 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Ohio | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF205L | 61.68 | LNGLF205LR | 67.17 | 9/30/2016 | Previous Tier 1 LNG022; 33.19 | Bio-LNG | Clean Energy (5481) | LES Renewable NG, LLC SWACO Facility (71157) | Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1R-1116 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Washington | Landfill Gas - CNG | Compressed Natural Gas | CNG009_1 | 13.67 | CNGLF210L | 30.90 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Cedar Hills Landfill, BioEnergy, LLC (71109) | Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1117 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | Washington | Landfill Gas - CNG | Compressed Natural Gas | CNGLF229L | 37.29 | CNGLF229LR | 42.78 | 9/30/2016 | Previous Tier 1 CNG011; 20.23 | Bio-CNG | Clean Energy (5481) | Cedar Hills Landfill, BioEnergy, LLC (71109) | Washington landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1118 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Washington | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF206L | 34.72 | LNGLF206LR | 40.21 | 9/30/2016 | Previous Tier 1 LNG014; 18.14 | Bio-LNG | Clean Energy (5481) | Cedar Hills Landfill, BioEnergy, LLC (71109) | Washington landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1R-1119 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | Canada | Landfill Gas - CNG | Compressed Natural Gas | CNGLF211L | 38.56 | CNGLF211LR | 44.05 | 9/30/2016 | Previous Tier 1 CNG049; 13.96 | Bio-CNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1120 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Canada | Landfill Gas - CNG | Compressed Natural Gas | CNG048 | 7.36 | CNGLF212L | 31.96 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1121 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Canada | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF207L | 37.03 | LNGLF207LR | 41.44 | 9/30/2016 | Previous Tier 1 LNG033; 11.84 | Bio-LNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1N-1540 | Tier 1 | 2.0 | Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional) | Louisiana | Landfill Gas | Compressed Natural Gas | CNGLF238 | 39.73 | CNGLF238R | 43.72 | 2/6/2019 | None | Bio-CNG | Athens Services (A431) | Irwindale (V5355) | River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional) | None | Retired |
| T1R-1100 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA | Michigan | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF223L | 51.80 | CNGLF223LR | 57.29 | 9/30/2016 | Previous Tier 1 CNG032; 32.24 | Bio-CNG | Clean Energy (5481) | Westside Gas Producers LLC (71151) | Michigan landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1125 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Kansas | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF209L | 48.53 | LNGLF209LR | 54.02 | 9/30/2016 | Previous Tier 1 LNG024; 30.8 | Bio-LNG | Clean Energy (5481) | EIF KC Landfill Gas LLC (71155) | Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1N-1635 | Tier 1 | 2.0 | Fuel Producer: Nardini Agroindustrial Ltda (4229) Facility Name: Nardini Agroindustrial Ltda (70525): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS232 | 46.88 | 2/2/2017 | None | Ethanol | Nardini Agroindustrial Ltda (4229) | Nardini Agroindustrial Ltda (70525) | Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1480 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS239 | 44.53 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Usina São José da Estiva SA Açúcar e Álcool (70431) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1481 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting and electricity credit. | Brazil | Molasses | Ethanol | ETHM208L | 46.14 | ETHM237 | 45.06 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Usina São José da Estiva SA Açúcar e Álcool (70431) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting and electricity credit | None | Retired |
| T1N-1139 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Barra (70210) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM214 | 47.05 | 6/6/2016 | None | Ethanol | Raízen Energia S/A (3805) | Barra (70210) | Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1R-1178 | Tier 1 | 2.0 | Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG co-product | California | Sugarcane | Ethanol | ETHS026 | 54.47 | ETHS202L | 22.44 | 3/31/2016 | None | Ethanol | California Ethanol & Power [CE+P] IV1 (C088) | CE+P IV1 (90-08) | California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG coproduct | None | Retired |
| T1N-1394 | Tier 1 | 2.0 | Fuel Producer: Usina Alto Alegre S/A - Açúcar e Álcool (5565) Facility Name: Unidade Junqueira (71018). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS215 | 47.23 | 12/20/2016 | None | Ethanol | Usina Alto Alegre S/A Açúcar e Álcool (5565) | Unidade Junqueira (71018) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1142 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Benálcool (70549): Brazilian sugarcane molasses-based ethanol pathway, with credit for mechanized harvesting | Brazil | Molasses | Ethanol | None | None | ETHM234 | 47.63 | 5/19/2017 | None | Ethanol | Raízen Energia S/A (3805) | Benálcool (70549) | Brazilian sugarcane molassesbased ethanol pathway, with credit for mechanized harvesting | None | Retired |
| T1N-1065 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS208 | 47.68 | 6/6/2016 | None | Ethanol | BIOSEV SA (3869) | Unidade MB (70568) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1189 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS206 | 47.73 | 6/6/2016 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | USINA FRUTAL AÇÚCAR E ÁLCOOL (70579) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1145 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Junqueira (70553): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM217 | 47.82 | 7/8/2016 | None | Ethanol | Raízen Energia S/A (3805) | Junqueira (70553) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1061 | Tier 1 | 2.0 | Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Unidade Cantaduva (71061): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS225 | 47.86 | 12/20/2016 | None | Ethanol | Noble Brasil SA (4232) | Unidade Cantaduva (71061) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1371 | Tier 1 | 2.0 | Fuel Producer: Guarani SA (3890) Facility Name: Andrade Açúcar e Álcool SA (70451): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS226 | 47.89 | 12/20/2016 | None | Ethanol | Guarani SA (3890) | Andrade Açúcar e Álcool SA (70451) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1395 | Tier 1 | 2.0 | Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Santa Cruz S/A Açúcar e Álcool (70484). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS223 | 48.22 | 12/20/2016 | None | Ethanol | Usina São Martinho SA (3867) | Santa Cruz S/A Açúcar e Álcool (70484) | Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1463 | Tier 1 | 2.0 | Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Santa Candida (70500). Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS224 | 48.35 | 12/20/2016 | None | Ethanol | Tonon Bioenergia SA (4214) | Santa Candida (70500) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1377 | Tier 1 | 2.0 | Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Usina Conquista do Pontal S/A (70494): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS231 | 48.39 | 12/20/2016 | None | Ethanol | Odebrecht Agroindustrial SA (5580) | Usina Conquista do Pontal S/A (70494) | Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1077 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM228 | 48.63 | 2/15/2017 | None | Ethanol | BIOSEV SA (3869) | Unidade MB (70568) | Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1759 | Tier 1 | 2.0 | Fuel Producer: Questar Fueling Company (Q500) Facility Name: River Birch, LLC (Sharing) (K200W): River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California **(Provisional)** | Louisiana | Landfill Gas | Compressed Natural Gas | CNGLF245 | 40.62 | CNGLF245R | 43.98 | 2/6/2019 | None | Bio-CNG | Questar Fueling Company (Q500) | River Birch, LLC (Sharing)(K200W) | River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California (Provisional) | None | Retired |
| T1R-1108 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | New York | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF226L | 56.21 | CNGLF226LR | 61.70 | 9/30/2016 | Previous Tier 1 CNG028; 34.15 | Bio-CNG | Clean Energy (5481) | Seneca Energy II, LLC (71156) | New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1225 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA | Montana | Landfill Gas - LNG | Liquefied Natural Gas | LNGLF210L | 47.3 | LNGLF210LR | 52.79 | 9/30/2016 | Previous Tier 1 LNG036; 49.76 | Bio-LNG | Clean Energy (5481) | MontanaDakota Utilities Billings Regional Landfill (71193) | Montana landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA | None | Retired |
| T1N-1482 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS238 | 46.05 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Usina Santa Adélia SA (70404) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1483 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM210L | 45.85 | ETHM236 | 47.27 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Usina Santa Adélia SA (70404) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1459 | Tier 1 | 2.0 | Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Delta (70367). Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS220 | 49.69 | 12/20/2016 | None | Ethanol | Usina Delta SA (3852) | Usina Delta S/A Unidade Delta (70367) | Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1616 | Tier 1 | 2.0 | Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Tapejara (70464): Brazilian sugarcane molasses-based ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity. | Brazil | Molasses | Ethanol | None | None | ETHM224 | 52.78 | 12/20/2016 | None | Ethanol | Usina de Açúcar Santa Terezinha Ltda (3921) | Usina de Açúcar Santa Terezinha Unidade Tapejara (70464) | Brazilian sugarcane molassesbased ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1462 | Tier 1 | 2.0 | Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Vista Alegre (70499): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS230 | 53.40 | 12/20/2016 | None | Ethanol | Tonon Bioenergia SA (4214) | Vista Alegre (70499) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1516 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC123 | 60.74 | ETHC269L | 53.49 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | None | Retired |
| T1R-1258 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660). North American Natural Gas pipelined to Ehrenberg (AZ) for liquefaction, then transported by truck to CA | Arizona | North American NG - LNG | Liquefied Natural Gas | LNG010 | 76.25 | LNGF200L | 86.22 | 9/30/2016 | None | Fossil LNG | Clean Energy (5481) | Ehrenberg LNG (C0660) | North American Natural Gas pipelined to Ehrenberg (AZ)for liquefaction, then transported by truck to CA | None | Retired |
| T1N-1614 | Tier 1 | 2.0 | Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Terra Rica (71032): Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports. | Brazil | Sugarcane | Ethanol | None | None | ETHS228 | 53.69 | 12/20/2016 | None | Ethanol | Usina de Açúcar Santa Terezinha Ltda (3921) | Usina de Açúcar Santa Terezinha Unidade Terra Rica (71032) | Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports | None | Retired |
| T1R-1264 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | Brazil | Molasses | Ethanol | ETHM013 | 67.64 | ETHM209L | 46.04 | 3/31/2016 | None | Ethanol | Copersucar (3702) | Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419) | Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | None | Retired |
| T1N-1607 | Tier 1 | 2.0 | Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade de Ivaté (71030): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM222 | 54.37 | 12/20/2016 | None | Ethanol | Usina de Açúcar Santa Terezinha Ltda (3921) | Usina de Açúcar Santa Terezinha Unidade de Ivaté (71030) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1280 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA | Michigan | Landfill Gas - LNG | Liquefied Natural Gas | LNG017 | 24.90 | LNGLF211L | 55.38 | 9/30/2016 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Blue Skies Energy (71132) | Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA | None | Retired |
| T1R-1329 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA | Texas | Landfill Gas - L-CNG | Compressed Natural Gas | CNG034 | 27.85 | CNGLF234L | 57.58 | 9/30/2016 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | McCarty Road LFG Recovery Facility (71135) | Texas landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA | None | Retired |
| T1R-1282 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to California via pipeline for liquefaction | Michigan | Landfill Gas - LNG | Liquefied Natural Gas | LNG019 | 21.68 | LNGLF212L | 44.25 | 9/30/2016 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Blue Skies Energy (71132) | Michigan Landfill gas to pipelinequality biomethane, delivered to California via pipeline for liquefaction | None | Retired |
| T1R-1105 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA | Tennessee | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF225L | 57.72 | CNGLF225LR | 63.21 | 9/30/2016 | Previous Tier 1 CNG035; 45.95 | Bio-CNG | Clean Energy (5481) | CERF Shelby LLC (71163) | CERF Shelby landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA | None | Retired |
| T2N-1099 | Tier 2 | 2.0 | Fuel Producer: AltEn, LLC (6269) Facility Name: AltEn (70131): Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas. (Provisional) | Nebraska | Spent Corn and Sorghum Seeds | Ethanol | None | None | ETHCSS200 | 59.29 | 12/26/2016 | Application Package | Ethanol | AltEn, LLC (6269) | AltEn (70131) | Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas(Provisional) | None | Retired |
| T1R-1305 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Pioneiros Bioenergia S.A. (70430). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | Brazil | Molasses | Ethanol | ETHM017 | 58.48 | ETHM211L | 45.01 | 3/31/2016 | None | Ethanol | Copersucar (3702) | Pioneiros Bioenergia SA (70430) | Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1318 | Tier 1 | 2.0 | Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: RiverBirch LLC (K2000). Louisiana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional) | Louisiana | Landfill Gas - CNG | Compressed Natural Gas | CNGLF215L | 37.23 | CNGLF215LR | 43.06 | 2/6/2019 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | RiverBirch LLC (K2000) | Louisiana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional) | None | Retired |
| T1R-1319 | Tier 1 | 2.0 | Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: McCarty Road Landfill (L9416). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | CNG042 | 19.82 | CNGLF216L | 38.02 | 9/30/2016 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | McCarty Road Landfill (L9416) | Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA | None | Retired |
| T1R-1110 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; compressed in CA | Texas | Landfill Gas | Compressed Natural Gas | CNG016 | 28.42 | CNGLF208L | 41.35 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Dallas Clean Energy McCommas Bluff (71009) | Texas landfill gas to biomethane; delivered by pipeline; compressed in CA | None | Retired |
| T1R-1322 | Tier 1 | 2.0 | Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: BFI Usine de Triage Lachenaie Ltd (C3779). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Canada | Landfill Gas - CNG | Compressed Natural Gas | CNG045 | 7.04 | CNGLF218L | 32.27 | 9/30/2016 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | BFI Usine de Triage Lachenaie Ltd (C3779) | Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1324 | Tier 1 | 2.0 | Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Cedar Hills Landfill, LLC (71136). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | California | Landfill Gas - CNG | Compressed Natural Gas | CNG010 | 13.36 | CNGLF219L | 30.50 | 9/30/2016 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | Cedar Hills Landfill, LLC (71136) | Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1326 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA | Arizona | North American NG - LNG | Liquefied Natural Gas | LNG011_1 | 76.48 | LNGF201L | 87.73 | 9/30/2016 | None | Fossil LNG | Applied Natural Gas Fuels, Inc. (6174) | Needle Mountain LNG PLant (95116) | North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA | None | Retired |
| T1R-1327 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; re-gasified and compressed to L-CNG in CA | Arizona | North American NG - L-CNG | Compressed Natural Gas | CNG015 | 76.87 | CNGF202L | 90.33 | 9/30/2016 | None | Fossil CNG | Applied Natural Gas Fuels, Inc. (6174) | Needle Mountain LNG PLant (95116) | North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1328 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA | Texas | Landfill Gas - LNG | Liquefied Natural Gas | LNG027 | 27.45 | LNGLF213L | 55.05 | 9/30/2016 | None | Bio-LNG | Applied Natural Gas Fuels, Inc. (6174) | McCarty Road LFG Recovery Facility (71135) | Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA | None | Retired |
| T1R-1333 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; re-gasified and compressed to L-CNG in CA | New York | Landfill Gas - L-CNG | Compressed Natural Gas | CNG046 | 32.24 | CNGLF236L | 59.34 | 9/30/2016 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | Fresh Kills Landfill (71203) | New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1330 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA | Arizona | Landfill Gas - LNG | Liquefied Natural Gas | LNG012_1 | 40.91 | LNGLF214L | 76.61 | 9/30/2016 | None | Bio-LNG | Applied Natural Gas Fuels, Inc. (6174) | Fort Bend Landfill Recovery (71139) | North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA | None | Retired |
| T1R-1281 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; re-gasified and compressed to L-CNG | Michigan | Landfill Gas - L-CNG | Compressed Natural Gas | CNG014 | 25.30 | CNGLF232L | 59.36 | 9/30/2016 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Blue Skies Energy (71132) | Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; regasified and compressed to LCNG | None | Retired |
| T1R-1332 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA | New York | Landfill Gas - LNG | Liquefied Natural Gas | LNG032 | 31.84 | LNGLF215L | 56.74 | 9/30/2016 | None | Bio-LNG | Applied Natural Gas Fuels, Inc. (6174) | Fresh Kills Landfill (71203) | New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1114 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA | Ohio | Landfill Gas - L-CNG | Compressed Natural Gas | CNGLF228L | 64.28 | CNGLF228LR | 71.31 | 9/30/2016 | Previous Tier 1 CNG026; 35.31 | Bio-CNG | Clean Energy (5481) | LES Renewable NG, LLC SWACO Facility (71157) | Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA | None | Retired |
| T1R-1359 | Tier 1 | 2.0 | Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Canada | Landfill Gas - CNG | Compressed Natural Gas | CNG050 | 6.28 | CNGLF220L | 31.17 | 9/30/2016 | None | Bio-CNG | SunLine Transit Agency (S317) | Sunline Transit (H2505) | Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1364 | Tier 1 | 2.0 | Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity | Biodiesel | Tallow | Biodiesel | BIOD039 | 57.84 | BDT207L | 37.97 | 12/20/2016 | None | Biodiesel | Universal Biofuels Private, Ltd (6213) | Universal Biofuels Private, Ltd (82702) | Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity | None | Retired |
| T1R-1365 | Tier 1 | 2.0 | Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Used Cooking Oil sourced world-wide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity | Biodiesel | UCO | Biodiesel | BIOD040 | 24.45 | BDU212L | 26.07 | 12/20/2016 | None | Biodiesel | Universal Biofuels Private, Ltd (6213) | Universal Biofuels Private, Ltd (82702) | Used Cooking Oil sourced worldwide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity | None | Retired |
| T1R-1396 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | CNG043 | 24.49 | CNGLF221L | 38.02 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA | None | Retired |
| T2R-1044 | Tier 2 | 2.0 | Fuel Producer: Trestle Energy LLC (T315) Facility Name: Golden Grain Energy, LLC (shared facility) (7069S). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG | Iowa | Corn | Ethanol | ETHC116 | 70.65 | ETHC273L | 59.60 | 3/31/2016 | None | Ethanol | Trestle Energy LLC (T315) | Golden Grain Energy, LLC(shared facility)(7069S) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T2R-1047 | Tier 2 | 2.0 | Fuel Producer: Poet DSM Project Liberty LLC (6232) Facility Name: Poet DSM Project Liberty LLC (71164). Corn Stover residue-based cellulosic ethanol with surplus steam and biogas export co-product credits | Iowa | Corn Stover | Ethanol | ETHB004 | 21.58 | ETHCS201L | 21.58 | 3/31/2016 | None | Ethanol - Cellulosic | Poet DSM Project Liberty LLC (6232) | Poet DSM Project Liberty LLC (71164) | Corn Stover residuebased cellulosic ethanol with surplus steam and biogas export coproduct credits | None | Retired |
| T2R-1015 | Tier 2 | 2.0 | Fuel Producer: Abengoa Bioenergia Agroindustria Ltda (3924) Facility Name: Abengoa - São Luiz (70473). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | Brazil | Molasses | Ethanol | ETHM010 | 54.92 | ETHM213L | 42.06 | 3/31/2016 | None | Ethanol | Abengoa Bioenergia Agroindustria Ltda (3924) | Abengoa São Luiz (70473) | Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T2R-1033 | Tier 2 | 2.0 | Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to hydrogen production via cracking of methane and transport by tube trailer | California | Landfill Gas | Hydrogen | HYGN010 | -32.36 | HYGLF200L | -5.28 | 9/30/2016 | None | Hydrogen | LytEn (L700) | LytEn (K4933) | Landfill gas to hydrogen production via cracking of methane and transport by tube trailer | None | Retired |
| T2R-1034 | Tier 2 | 2.0 | Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to on-site hydrogen production via cracking of methane | California | Fossil NG & Landfill Gas | Hydrogen | HYGN007 | 15.29 | HYGFLF200L | 40.36 | 9/30/2016 | None | Hydrogen | LytEn (L700) | LytEn (K4933) | North American fossil NG and landfill gas to onsite hydrogen production via cracking of methane | None | Retired |
| T2R-1035 | Tier 2 | 2.0 | Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to on-site hydrogen production via cracking of methane | California | Landfill Gas | Hydrogen | HYGN008 | -46.91 | HYGLF201L | -12.65 | 9/30/2016 | None | Hydrogen | LytEn (L700) | LytEn (K4933) | Landfill gas to onsite hydrogen production via cracking of methane | None | Retired |
| T2R-1036 | Tier 2 | 2.0 | Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer | California | Fossil NG & Landfill Gas | Hydrogen | HYGN009 | 29.84 | HYGFLF201L | 47.73 | 9/30/2016 | None | Hydrogen | LytEn (L700) | LytEn (K4933) | North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2R-1038 | Tier 2 | 2.0 | Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG co-product | California | Sorghum | Ethanol | ETHG022 | 39.00 | ETHG213L | 30.63 | 3/31/2016 | None | Ethanol | California Ethanol & Power [CE+P] IV1 (C088) | CE+P IV1 (90-08) | Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG coproduct | None | Retired |
| T2R-1039 | Tier 2 | 2.0 | Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Spain sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain | Spain | Used Cooking Oil (Spain) | Biodiesel | BIOD036 | 20.74 | BDU208L | 22.17 | 6/30/2016 | None | Biodiesel | Biocom Energia (6099) | Biocom Energia (81607) | Spain sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain | None | Retired |
| T2R-1040 | Tier 2 | 2.0 | Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): European sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain | Spain | Used Cooking Oil (Europe) | Biodiesel | BIOD037 | 21.17 | BDU209L | 21.77 | 6/30/2016 | None | Biodiesel | Biocom Energia (6099) | Biocom Energia (81607) | European sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain | None | Retired |
| T2R-1041 | Tier 2 | 2.0 | Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Low-free fatty acids (Used Cooking Oil) sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain | Spain | Used Cooking Oil (Global) | Biodiesel | BIOD038 | 26.03 | BDU210L | 26.83 | 6/30/2016 | None | Biodiesel | Biocom Energia (6099) | Biocom Energia (81607) | Lowfree fatty acids (Used Cooking Oil)sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain | None | Retired |
| T2R-1043 | Tier 2 | 2.0 | Fuel Producer: Fulcrum Sierra BioFuels, LLC (F197) Facility Name: Fulcrum Sierra BioFuels, LLC (P3600). Fisher-Tropsch (FT) Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW) | Nevada | Municipal Solid Waste (MSW) | Fischer-Tropsch Diesel (FTD) | FTD001 | 37.47 | FTDMW200L | 14.78 | 9/30/2016 | None | FT Diesel | Fulcrum Sierra BioFuels, LLC (F197) | Fulcrum Sierra BioFuels, LLC (P3600) | FisherTropsch (FT)Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW) | None | Retired |
| T2R-1077 | Tier 2 | 2.0 | Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Wheat Straw residue-based cellulosic ethanol with electricity co-product credit | Kansas | Wheat Straw | Ethanol | ETHB003 | 23.36 | ETHWS200L | 24.20 | 3/31/2016 | None | Ethanol - Cellulosic | Abengoa Bioenergy Biomass of Kansas (6254) | Abengoa Bioenergy Biomass of Kansas, LLC (71183) | Wheat Straw residuebased cellulosic ethanol with electricity coproduct credit | None | Retired |
| T2R-1011 | Tier 2 | 2.0 | Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Corn Stover residue-based cellulosic ethanol with electricity co-product credit | Brazil | Corn Stover | Ethanol | ETHB002 | 29.52 | ETHCS200L | 32.82 | 3/31/2016 | None | Ethanol - Cellulosic | Abengoa Bioenergy Biomass of Kansas (6254) | Abengoa Bioenergy Biomass of Kansas, LLC (71183) | Corn Stover residuebased cellulosic ethanol with electricity coproduct credit | None | Retired |
| T2R-1068 | Tier 2 | 2.0 | Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA | Canada | Pyrolysis Oil from Forest Residue | Renewable Gasoline | RNWG001 | 20.12 | RGFRP200L | 21.17 | 9/30/2016 | None | Renewable Gasoline | Ensyn Technologies Inc (6179) | Ensyn Ontario Facility (82219) | Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA | None | Retired |
| T2R-1069 | Tier 2 | 2.0 | Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA | Canada | Pyrolysis Oil from Forest Residue | Renewable Gasoline | RNWG002 | 25.03 | RGFRP201L | 26.08 | 9/30/2016 | None | Renewable Gasoline | Ensyn Technologies Inc (6179) | Ensyn Ontario Facility (82219) | Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA | None | Retired |
| T2R-1070 | Tier 2 | 2.0 | Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA | Canada | Pyrolysis Oil from Forest Residue | Biodiesel | RNWD028 | 21.67 | RDFRP200L | 22.42 | 9/30/2016 | None | Renewable Diesel | Ensyn Technologies Inc (6179) | Ensyn Ontario Facility (82219) | Renewable diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA | None | Retired |
| T2R-1071 | Tier 2 | 2.0 | Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA | Canada | Pyrolysis Oil from Forest Residue | Renewable Diesel | RNWD029 | 25.58 | RDFRP201L | 27.33 | 9/30/2016 | None | Renewable Diesel | Ensyn Technologies Inc (6179) | Ensyn Ontario Facility (82219) | Renewbale diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA | None | Retired |
| T2R-1050 | Tier 2 | 2.0 | Fuel Producer: GranBio Investimentos S,A (6260) Facility Name: Bioflex AgroIndustrial SA (71192). Brazilian sugarcane straw residue-based cellulosic ethanol, with credit for electricity cogeneration and surplus export | Brazil | Sugarcane Straw | Ethanol | ETHB001 | 6.98 | ETHSS200L | 33.82 | 3/31/2016 | None | Ethanol - Cellulosic | GranBio Investimentos S.A (6260) | Bioflex AgroIndustrial SA (71192) | Brazilian sugarcane straw residuebased cellulosic ethanol, with credit for electricity cogeneration and surplus export | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2R-1080 | Tier 2 | 2.0 | Fuel Producer: Alameda-Contra Costa Transit District (A149) Facility Name: Division 2 (F1600). Hydrogen production via electrolysis using solar electricity | California | Solar Elericity via Electrolysis | Hydrogen | HYGN006 | 0.00 | HYGE200L | 0.00 | 9/30/2016 | None | Hydrogen | AlamedaContra Costa Transit District (A149) | Division 2 (F1600) | Hydrogen production via electrolysis using solar electricity | None | Retired |
| T1R-1193 | Tier 1 | 2.0 | Fuel Producer: Green Plains Hereford LLC (6327) Facility Name: Green Plains Hereford LLC (70534). Midwest, Corn Ethanol, Dry Mill, NG | Texas | Corn | Ethanol | ETHC072 | 78.90 | ETHC248L | 67.60 | 3/31/2016 | None | Ethanol | Green Plains Hereford LLC (6327) | Green Plains Hereford LLC (70534) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T2R-1117 | Tier 2 | 2.0 | Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Asian Used Cooking Oil to Renewable Diesel Produced in Singapore. | Singapore | Asian Used Cooking Oil | Renewable Diesel | RNWD009 | 16.21 | RDU200L | 16.89 | 6/30/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Asian Used Cooking Oil to Renewable Diesel Produced in Singapore | None | Retired |
| None | Lookup Table | 3.0 | California grid electricity used as a transportation fuel in California | California | Grid Electricity (039) | Electricity (ELC) | None | None | ELC000L00072019 | 81.49 | NA | None | Electricity | NA | NA | California grid electricity used as a transportation fuel in California | None | Retired |
| T1N-1063 | Tier 1 | 2.0 | Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UM) (70528): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS227 | 45.22 | 12/20/2016 | None | Ethanol | Noble Brasil SA (4232) | Noble Brasil S/A NBSA (UM)(70528) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1079 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Santa Elisa (71070). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM201 | 45.50 | 3/31/2016 | None | Ethanol | BIOSEV SA (3869) | Usina Santa Elisa (71070) | Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1085 | Tier 1 | 2.0 | Fuel Producer: USJ Açúcar e Álcool SA (3878) Facility Name: USJ Açúcar e Álcool S/A (70441): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS209 | 46.26 | 7/8/2016 | None | Ethanol | USJ Açúcar e Álcool SA (3878) | USJ Açúcar e Álcool S/A (70441) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1096 | Tier 1 | 2.0 | Fuel Producer: Glencane Bioenergia SA (4429) Facility Name: Glencane Bioenergia SA (71008). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS222 | 46.30 | 12/20/2016 | None | Ethanol | Glencane Bioenergia SA (4429) | Glencane Bioenergia SA (71008) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1R-1214 | Tier 1 | 2.0 | Fuel Producer: Green Plains Central City (3368) Facility Name: Green Plains Central City LLC (70141). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC023 | 82.17 | ETHC252L | 70.71 | 3/31/2016 | None | Ethanol | Green Plains Central City (3368) | Green Plains Central City LLC (70141) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1070 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | Texas | Corn | Ethanol | None | None | ETHC200 | 70.79 | 3/31/2016 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | None | Retired |
| T1N-1134 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Serra (70559): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM226 | 42.84 | 2/2/2017 | None | Ethanol | Raízen Energia S/A (3805) | Serra (70559) | Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1135 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Ipaussu (71058): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export. | Brazil | Molasses | Ethanol | None | None | ETHM220 | 44.39 | 12/20/2016 | None | Ethanol | Raízen Energia S/A (3805) | Ipaussu (71058) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1569 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS | Kansas | Corn | Ethanol | None | None | ETHC281 | 72.32 | 2/2/2017 | None | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS | None | Retired |
| T1N-1147 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Univalem (70550): Brazilian sugarcane molasses-to-ethanol pathway, with credit for mechanized harvesting | Brazil | Molasses | Ethanol | None | None | ETHM233 | 44.94 | 5/19/2017 | None | Ethanol | Raízen Energia S/A (3805) | Univalem (70550) | Brazilian sugarcane molassestoethanol pathway, with credit for mechanized harvesting | None | Retired |
| T1N-1187 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS200 | 46.19 | 3/31/2016 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1R-1088 | Tier 1 | 2.0 | Fuel Producer: Granite Falls Energy, LLC (4769) Facility Name: Granite Falls Energy, LLC (70071). Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG | Minnesota | Corn | Ethanol | ETHC094 | 85.08 | ETHC242L | 74.30 | 3/31/2016 | None | Ethanol | Granite Falls Energy, LLC (4769) | Granite Falls Energy, LLC (70071) | Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG | None | Retired |
| T1R-1270 T1R-1271 | Tier 1 | 2.0 | Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Albion (70283). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG | Nebraska | Corn | Ethanol | ETHC106 ETHC107 | 86.49 82.37 | ETHC261L | 74.66 | 3/31/2016 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Albion (70283) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG | None | Retired |
| T1N-1277 | Tier 1 | 2.0 | Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG | Nebraska | Corn | Ethanol | None | None | ETHC222 | 74.74 | 3/31/2016 | None | Ethanol | Elkhorn Valley Ethanol LLC (4833) | Elkhorn Valley Ethanol LLC (70095) | Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG | None | Retired |
| T1N-1306 | Tier 1 | 2.0 | Fuel Producer: SeQuential (6129) Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525): Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles) to Biodiesel produced in Oregon | Oregon | Used Cooking Oil | Biodiesel | None | None | BDU213 | 25.67 | 7/1/2016 | None | Biodiesel | SeQuential (6129) | SeQuentialPacific Biodiesel, LLC(83525) | Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles)to Biodiesel produced in Oregon | None | Retired |
| T1R-1221 | Tier 1 | 2.0 | Fuel Producer: Green Plains Ord LLC (3360) Facility Name: Green Plains Ord LLC (70138). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC040 | 85.84 | ETHC255L | 74.84 | 3/31/2016 | None | Ethanol | Green Plains Ord LLC (3360) | Green Plains Ord LLC (70138) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1320 | Tier 1 | 2.0 | Fuel Producer: Los Angeles County Metropolitan Transportation Authority (L440) Facility Name: LA Metro Aggregate (G0001). North American NG delivered via pipeline; compressed in CA | California | North American NG - CNG | Compressed Natural Gas | None | None | CNGF200 | 80.59 | 9/30/2016 | None | Fossil CNG | Los Angeles County Metropolitan Transportation Authority (L440) | LA Metro Aggregate (G0001) | North American NG delivered via pipeline; compressed in CA | None | Retired |
| T1R-1219 | Tier 1 | 2.0 | Fuel Producer: Green Plains Shenandoah LLC (5073) Facility Name: Green Plains Shenandoah LLC (70149). Midwest, Corn Ethanol, Dry Mill, NG | Iowa | Corn | Ethanol | ETHC041 | 85.73 | ETHC254L | 74.87 | 3/31/2016 | None | Ethanol | Green Plains Shenandoah LLC (5073) | Green Plains Shenandoah LLC (70149) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1186 | Tier 1 | 2.0 | Fuel Producer: Highwater Ethanol, LLC (3303) Facility Name: Highwater Ethanol, LLC (70235). Midwest, Corn Ethanol, Dry Mill, NG | Minnesota | Corn | Ethanol | ETHC115 | 85.90 | ETHC247L | 75.15 | 3/31/2016 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1336 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Canola Oil; Fuel produced in California | Stockton, California | Canola | Biodiesel | None | None | BDCA201 | 54.97 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Biodiesel produced from Midwest Canola Oil; Fuel produced in California | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1338 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF200 | 33.56 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1339 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Corn Oil; Fuel produced in California | Stockton, California | Corn Oil from Wet DGS | Biodiesel | None | None | BDC204 | 29.42 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Biodiesel produced from Midwest Corn Oil; Fuel produced in California | None | Retired |
| T1N-1340 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Midwest Soybean; Biodiesel produced in California | Stockton, California | Soybean | Biodiesel | None | None | BDS201 | 52.45 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Midwest Soybean; Biodiesel produced in California | None | Retired |
| T1N-1341 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): North American high energy rendered Tallow; Biodiesel Produced in California | Stockton, California | Tallow | Biodiesel | None | None | BDT205 | 32.34 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | North American high energy rendered Tallow; Biodiesel Produced in California | None | Retired |
| T1N-1343 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): California high energy rendered Used Cooking Oil (UCO); Biodiesel Produced in California | Stockton, California | Used Cooking Oil | Biodiesel | None | None | BDU206 | 16.31 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | California high energy rendered Used Cooking Oil (UCO)Biodiesel Produced in California | None | Retired |
| T1N-1756 | Tier 1 | 2.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169) Facility Name: Hankinson Renewable Energy, LLC (70288): Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG | North Dakota | Corn | Ethanol | None | None | ETHC287 | 75.23 | 6/27/2017 | None | Ethanol | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG | None | Retired |
| T1N-1346 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF201 | 36.17 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1347 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF202 | 34.82 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1348 | Tier 1 | 2.0 | Fuel Producer: Pacific Gas and Electric Company (C460) Facility Name: PG&E CNG Fueling Stations (M4675). North American NG delivered via pipeline; compressed in California | California | North American NG | Compressed Natural Gas | None | None | CNGF204 | 80.59 | 11/2/2016 | None | Fossil CNG | Pacific Gas and Electric Company (C460) | PG&E CNG Fueling Stations (M4675) | North American NG delivered via pipeline; compressed in California | None | Retired |
| T1N-1354 | Tier 1 | 2.0 | Fuel Producer: CEVASA - Central Energetica Vale do Sapucai (3666) Facility Name: CEVASA - Central Energetica Vale do Sapucai (70701). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS201 | 44.02 | 3/31/2016 | None | Ethanol | CEVASA Central Energetica Vale do Sapucai (3666) | CEVASA Central Energetica Vale do Sapucai (70701) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1368 | Tier 1 | 2.0 | Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California | Arkansas | Tallow | Biodiesel | None | None | BDT210 | 40.69 | 12/20/2016 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | US sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California | None | Retired |
| T1N-1279 | Tier 1 | 2.0 | Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG | Iowa | Corn | Ethanol | None | None | ETHC224 | 76.01 | 3/31/2016 | None | Ethanol | Louis Dreyfus Commodities Grand Junction LLC (3137) | Louis dreyfus Commodities Grand Junction LLC (70139) | Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1372 | Tier 1 | 2.0 | Fuel Producer: Guarani SA (3890) Facility Name: Usina Vertente Ltda. (70447): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS217 | 44.21 | 12/20/2016 | None | Ethanol | Guarani SA (3890) | Usina Vertente Ltda (70447) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1373 | Tier 1 | 2.0 | Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA | Louisiana | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF203 | 37.77 | 9/30/2016 | None | Bio-CNG | SunLine Transit Agency (S317) | Sunline Transit (H2505) | River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA | None | Retired |
| T1N-1375 | Tier 1 | 2.0 | Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Alto Taquari (71019). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS216 | 41.91 | 12/20/2016 | None | Ethanol | Odebrecht Agroindustrial SA (5580) | Alto Taquari (71019) | Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1R-1157 | Tier 1 | 2.0 | Fuel Producer: Flint Hill Resources (4071) Facility Name: Fairmont (70103). Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG | Nebraska | Corn | Ethanol | ETHC064 | 86.62 | ETHC243L | 76.14 | 3/31/2016 | None | Ethanol | Flint Hill Resources (4071) | Fairmont (70103) | Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG | None | Retired |
| T1R-1331 | Tier 1 | 2.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; re-gasified and compressed to L-CNG | Arizona | Landfill Gas - L-CNG | Compressed Natural Gas | CNG008_1 | 41.68 | CNGLF235L | 80.62 | 9/30/2016 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | Fort Bend Landfill Recovery (71139) | North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; regasified and compressed to LCNG | None | Retired |
| T1R-1169 | Tier 1 | 2.0 | Fuel Producer: Adkins Energy LLC (4767) Facility Name: Adkins Energy, LLC (70070). Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG | Illinois | Corn | Ethanol | ETHC114 | 86.33 | ETHC244L | 76.27 | 3/31/2016 | None | Ethanol | Adkins Energy LLC (4767) | Adkins Energy, LLC (70070) | Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG | None | Retired |
| T1N-1235 | Tier 1 | 2.0 | Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG | North Dakota | Corn | Ethanol | None | None | ETHC219 | 76.46 | 3/31/2016 | None | Ethanol | Red Trail Energy LLC (4803) | Red Trail Energy LLC (70077) | Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG | None | Retired |
| T1N-1397 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF204 | 33.85 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1398 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Texas | Landfill Gas - CNG | Compressed Natural Gas | None | None | CNGLF205 | 34.38 | 9/30/2016 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers(shared facility)(7113s) | Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1399 | Tier 1 | 2.0 | Fuel Producer: GHI Energy, LLC (6156) Facility Name: GHI Energy, LLC (B8000). North American NG delivered via pipeline; compressed in CA | Texas | North American NG - CNG | Compressed Natural Gas | None | None | CNGF201 | 79.58 | 9/30/2016 | None | Fossil CNG | GHI Energy, LLC (6156) | GHI Energy, LLC (B8000) | North American NG delivered via pipeline; compressed in CA | None | Retired |
| T1N-1403 | Tier 1 | 2.0 | Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Off-site Rendered Used Cooking Oil Biodiesel Produced in California | San Diego, California | Used Cooking Oil | Biodiesel | None | None | BDU201 | 15.86 | 6/30/2016 | None | Biodiesel | New Leaf Biofuel (7768) | New Leaf Biofuel (83541) | Offsite Rendered Used Cooking Oil Biodiesel Produced in California | None | Retired |
| T1N-1406 | Tier 1 | 2.0 | Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Agri Industries (81926): Canola oil (produced in western Canada) biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is co-located with crushing operation) | Canada | Canola | Biodiesel | None | None | BDCA202 | 51.33 | 6/30/2016 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Agri Industries (81926) | Canola oil (produced in western Canada)biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is colocated with crushing operation) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1457 | Tier 1 | 2.0 | Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Velva (82790): Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is co-located with crushing operation) | North Dakota | Canola | Biodiesel | None | None | BDCA203 | 52.25 | 6/30/2016 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Velva (82790) | Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is colocated with crushing operation) | None | Retired |
| T1R-1272 T1R-1273 | Tier 1 | 2.0 | Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Aurora (70041). Midwest, Corn Ethanol, Dry Mill, NG | South Dakota | Corn | Ethanol | ETHC108 ETHC109 | 88.85 85.39 | ETHC262L | 76.74 | 3/31/2016 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1323 | Tier 1 | 2.0 | Fuel Producer: Prairie Horizon Agri-Energy, LLC (4760) Facility Name: Prairie Horizon Agri Energy, LLC (70659). Midwest, Corn Ethanol, Dry Mill, NG | Kansas | Corn | Ethanol | None | None | ETHC226 | 76.84 | 3/31/2016 | None | Ethanol | Prairie Horizon AgriEnergy, LLC (4760) | Prairie Horizon Agri Energy, LLC (70659) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1464 | Tier 1 | 2.0 | Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA | Mexico, Missouri | Soybean | Biodiesel | None | None | BDS202 | 50.85 | 6/30/2016 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Mexico (82791) | Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA | None | Retired |
| T1N-1465 | Tier 1 | 2.0 | Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (81.9%) and 18.1% rail 311mi) | Deerfield, Missouri | Soybean | Biodiesel | None | None | BDS203 | 49.16 | 6/30/2016 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Mexico (82791) | Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (819% and 181% rail 311mi) | None | Retired |
| T1N-1466 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS233 | 45.40 | 3/17/2017 | None | Ethanol | Copersucar (3702) | Pedra Agroindustrial SA (70415) | Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1467 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM229 | 46.06 | 3/17/2017 | None | Ethanol | Copersucar (3702) | Pedra Agroindustrial SA (70415) | Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1468 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS229 | 43.56 | 12/20/2016 | None | Ethanol | Copersucar (3702) | Usina Iacanga Açúcar e Álcool Ltda (70398) | Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1469 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM225 | 44.77 | 12/20/2016 | None | Ethanol | Copersucar (3702) | Usina Iacanga Açúcar e Álcool Ltda (70398) | Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1489 | Tier 1 | 2.0 | Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California | Arkansas | Tallow | Biodiesel | None | None | BDT213 | 32.96 | 3/17/2017 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Crossett Biodiesel Pant (82217) | High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California | None | Retired |
| T1N-1490 | Tier 1 | 2.0 | Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California | Arkansas | Soybean | Biodiesel | None | None | BDS208 | 51.11 | 3/17/2017 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Crossett Biodiesel Pant (82217) | Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California | None | Retired |
| T1N-1502 | Tier 1 | 2.0 | Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California | Arkansas | Corn Oil | Biodiesel | None | None | BDC210 | 38.75 | 5/19/2017 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | US sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1503 | Tier 1 | 2.0 | Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California | Canada | Used Cooking Oil | Biodiesel | None | None | BDU216 | 27.45 | 11/7/2016 | None | Biodiesel | Rothsay, A Division of Darling International Canada Inc (6190) | Rothsay Biodiesel (83210) | High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California | None | Retired |
| T1R-1174 | Tier 1 | 2.0 | Fuel Producer: Heron Lake BioEnergy (4015) Facility Name: Heron Lake BioEnergy (70097). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG | Minnesota | Corn | Ethanol | ETHC091 | 88.69 | ETHC245L | 77.33 | 3/31/2016 | None | Ethanol | Heron Lake BioEnergy (4015) | Heron Lake BioEnergy (70097) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T1N-1512 | Tier 1 | 2.0 | Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California | Canada | Tallow | Biodiesel | None | None | BDT209 | 36.15 | 11/7/2016 | None | Biodiesel | Rothsay, A Division of Darling International Canada Inc (6190) | Rothsay Biodiesel (83210) | High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California | None | Retired |
| T1N-1534 | Tier 1 | 2.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728). Biodiesel produced from tallow (poultry fat) feedstock sourced in California only. | Stockton, California | Tallow | Biodiesel | None | None | BDT206 | 28.90 | 6/30/2016 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Biodiesel produced from tallow (poultry fat)feedstock sourced in California only | None | Retired |
| T1R-1123 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Kansas | Landfill Gas | Compressed Natural Gas | CNG029 | 26.38 | CNGLF213L | 41.49 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | EIF KC Landfill Gas LLC (71155) | Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1102 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Ohio | Landfill Gas | Compressed Natural Gas | CNG022 | 21.01 | CNGLF206L | 41.61 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Pinnacle Gas Producers, LLC (71153) | Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1661 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154) Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950): Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in Califirnia **(Provisional)** | Arkansas | Landfill Gas | Compressed Natural Gas | None | None | CNGLF254 | 42.15 | 7/10/2017 | None | Bio-CNG | Shell Energy North America (6154) | Cambrian Energy/Southtex Fort Smith Treaters (C5950) | Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in Califirnia (Provisional) | None | Retired |
| T1N-1667 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154) Facility Name: Edinburg Renewables LLC (J8601): Edinburg landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)** | Texas | Landfill Gas | Compressed Natural Gas | None | None | CNGLF249 | 43.26 | 6/27/2017 | None | Bio-CNG | Shell Energy North America (6154) | Edinburg Renewables LLC (J8601) | Edinburg landfill gas (TX)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional) | None | Retired |
| T1R-1223 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Montana | Landfill Gas | Compressed Natural Gas | CNG057 | 45.24 | CNGLF214L | 46.65 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | MontanaDakota Utilities Billings Regional Landfill (71193) | Montana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1R-1099 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Prodcuers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Michigan | Landfill Gas | Compressed Natural Gas | CNG031 | 25.62 | CNGLF237L | 47.40 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Westside Gas Prodcuers LLC (71151) | Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1551 | Tier 1 | 2.0 | Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Canola Oil Biodiesel produced in Washington; BD transported by rail to California | Hoquiam, Washinton | Canola | Biodiesel | None | None | BDCA204 | 52.87 | 8/11/2016 | None | Biodiesel | REG Grays Harbor, LLC (6326) | REG Grays Harbor, LLC (82954) | Canola Oil Biodiesel produced in Washington; BD transported by rail to California | None | Retired |
| T1N-1562 | Tier 1 | 2.0 | Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Used Cooking Oil (UCO) to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California | Hoquiam, Washinton | Used Cooking Oil | Biodiesel | None | None | BDU214 | 18.62 | 8/25/2016 | None | Biodiesel | REG Grays Harbor, LLC (6326) | REG Grays Harbor, LLC (82954) | Used Cooking Oil (UCO)to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1505 | Tier 1 | 2.0 | Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG | South Dakota | Corn | Ethanol | None | None | ETHC277 | 77.93 | 11/2/2016 | None | Ethanol | NuGen Energy, LLC (3332) | NuGen Energy, LLC (70195) | Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG | None | Retired |
| T1N-1274 | Tier 1 | 2.0 | Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG | Iowa | Corn | Ethanol | None | None | ETHC220 | 78.14 | 3/31/2016 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC Fort Dodge (70043) | Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG | None | Retired |
| T1R-1177 | Tier 1 | 2.0 | Fuel Producer: Advanced BioEnergy, LLC (4094) Facility Name: ABE South Dakota, LLC (70104). Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG | South Dakota | Corn | Ethanol | ETHC065 | 88.59 | ETHC246L | 78.32 | 3/31/2016 | None | Ethanol | Advanced BioEnergy, LLC (4094) | ABE South Dakota, LLC (70104) | Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG | None | Retired |
| T1N-1574 | Tier 1 | 2.0 | Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | Iowa | Canola Oil | Biodiesel | None | None | BDCA205 | 61.94 | 2/2/2017 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | None | Retired |
| T1N-1575 | Tier 1 | 2.0 | Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | Iowa | Corn Oil | Biodiesel | None | None | BDC206 | 29.46 | 2/2/2017 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | None | Retired |
| T1N-1576 | Tier 1 | 2.0 | Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | Iowa | Soybean Oil | Biodiesel | None | None | BDS206 | 54.50 | 2/2/2017 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California | None | Retired |
| T1N-1577 | Tier 1 | 2.0 | Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): U.S. sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California | Iowa | Tallow | Biodiesel | None | None | BDT211 | 31.19 | 2/2/2017 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | US sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California | None | Retired |
| T1N-1583 | Tier 1 | 2.0 | Fuel Producer: Ag Processing Inc (4552) Facility Name: Ag Processing Inc - Sgt. Bluff (81733): Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coal-boiler used; Fuel transported by rail to California | Iowa | Soybean | Biodiesel | None | None | BDS207 | 52.22 | 2/2/2017 | None | Biodiesel | Ag Processing Inc (4552) | Ag Processing Inc Sgt Bluff (81733) | Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coalboiler used; Fuel transported by rail to California | None | Retired |
| T1R-1268 T1R-1269 | Tier 1 | 2.0 | Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Albert City (70142). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG | Iowa | Corn | Ethanol | ETHC104_1 ETHC105_1 | 88.15 84.06 | ETHC260L | 78.62 | 3/31/2016 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC Albert City (70142) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG | None | Retired |
| T1N-1072 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG | Texas | Sorghum | Ethanol | None | None | ETHG200 | 79.03 | 3/31/2016 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG | None | Retired |
| T1N-1596 | Tier 1 | 2.0 | Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California | California | North American NG | Compressed Natural Gas | None | None | CNGF203 | 78.21 | 11/2/2016 | None | Fossil CNG | SunLine Transit Agency (S317) | Sunline Transit (H2505) | North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California | None | Retired |
| T1N-1598 | Tier 1 | 2.0 | Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California | Arkansas | Soybean | Biodiesel | None | None | BDS211 | 59.53 | 5/19/2017 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1602 | Tier 1 | 2.0 | Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): Average U.S. sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)** | California | Used Cooking Oil | Biodiesel | None | None | BDU219 | 21.73 | 1/27/2017 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Average US sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional) | None | Retired |
| T1N-1604 | Tier 1 | 2.0 | Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): U.S. sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)** | California | Corn Oil | Biodiesel | None | None | BDC205 | 34.66 | 1/27/2017 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | US sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California (Provisional) | None | Retired |
| T1R-1086 T1R-1087 | Tier 1 | 2.0 | Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Glacial Lakes Energy (70064). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG | South Dakota | Corn | Ethanol | ETHC058 ETHC059 | 91.18 86.69 | ETHC241L | 79.21 | 3/31/2016 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Glacial Lakes Energy (70064) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG | None | Retired |
| T1N-1610 | Tier 1 | 2.0 | Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California | Ontario, Canada | Used Cooking Oil | Biodiesel | None | None | BDU218 | 22.38 | 12/20/2016 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California | None | Retired |
| T1N-1276 | Tier 1 | 2.0 | Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | Nebraska | Corn | Ethanol | None | None | ETHC221 | 79.83 | 3/31/2016 | None | Ethanol | Elkhorn Valley Ethanol LLC (4833) | Elkhorn Valley Ethanol LLC (70095) | Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T1N-1278 | Tier 1 | 2.0 | Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | Iowa | Corn | Ethanol | None | None | ETHC223 | 80.18 | 3/31/2016 | None | Ethanol | Louis Dreyfus Commodities Grand Junction LLC (3137) | Louis dreyfus Commodities Grand Junction LLC (70139) | Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T1N-1620 | Tier 1 | 2.0 | Fuel Producer: Clinton Biodiesel, LLC (6485) Facility Name: Clinton Biodiesel LLC (82595): Soy oil Biodiesel produced from Midwest, transported by rail to California **(Provisional)** | Iowa | Soybean | Biodiesel | None | None | BDS205 | 54.81 | 12/20/2016 | None | Biodiesel | Clinton Biodiesel, LLC (6485) | Clinton Biodiesel LLC (82595) | Soy oil Biodiesel produced from Midwest, transported by rail to California (Provisional) | None | Retired |
| T1R-1321 | Tier 1 | 2.0 | Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Monroeville LFG, LLC (71136). Pennsylvania landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Pennsylvania | Landfill Gas | Compressed Natural Gas | CNG047 | 33.30 | CNGLF217L | 49.55 | 9/30/2016 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | Monroeville LFG, LLC (71136) | Pennsylvania landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1546 | Tier 1 | 2.0 | Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Seneca Meadows solid waste landfill (Waterloo NY) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG | New York | Landfill Gas | Compressed Natural Gas | None | None | CNGLF241 | 50.37 | 11/2/2016 | None | Bio-CNG | Athens Services (A431) | Irwindale (V5355) | Seneca Meadows solid waste landfill (Waterloo NY)gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG | None | Retired |
| T1N-1484 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS237 | 46.51 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Pioneiros Bioenergia SA (70430) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1107 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | New York | Landfill Gas | Compressed Natural Gas | CNG027 | 27.53 | CNGLF207L | 52.77 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | Seneca Energy II, LLC (71156) | New York landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T1N-1629 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona | Michigan | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF216 | 64.74 | 7/10/2017 | None | Bio-LNG | Clean Energy (5481) | Canton Renewables (71041) | Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1022 T1R-1023 | Tier 1 | 2.0 | Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Aberdeen Energy (70299). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG | South Dakota | Corn | Ethanol | ETHC060 ETHC061 | 92.15 87.66 | ETHC237L | 80.19 | 3/31/2016 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Aberdeen Energy (70299) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG | None | Retired |
| T1N-1636 | Tier 1 | 2.0 | Fuel Producer: Usina Alta Mogiana S/A (4225) Facility Name: Usina Alta Mogiana S.A. - Acucar e Alcool (70498): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM227 | 46.29 | 2/2/2017 | None | Ethanol | Usina Alta Mogiana S/A (4225) | Usina Alta Mogiana SA Acucar e Alcool (70498) | Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting | None | Retired |
| T1N-1647 | Tier 1 | 2.0 | Fuel Producer: Titan El Toro LLC (T153) Facility Name: Titan El Toro (T4201): North American NG delivered via pipeline; compressed in California | California | North American NG | Compressed Natural Gas | None | None | CNGF206 | 80.59 | 3/17/2017 | None | Fossil CNG | Titan El Toro LLC (T153) | Titan El Toro (T4201) | North American NG delivered via pipeline; compressed in California | None | Retired |
| T1N-1626 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | Michigan | Landfill Gas | Compressed Natural Gas | None | None | CNGLF251 | 57.35 | 6/27/2017 | None | Bio-CNG | Clean Energy (5481) | Canton Renewables (71041) | Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California | None | Retired |
| T1N-1666 | Tier 1 | 2.0 | Fuel Producer: GeoGreen Biofuels (3885) Facility Name: GeoGreen Biofuels (81199): California sourced Waste Oil (Used Cooking Oil) Biodiesel produced in California **(Provisional**) | California | Used Cooking Oil | Biodiesel | None | None | BDU222 | 18.26 | 3/17/2017 | None | Biodiesel | GeoGreen Biofuels (3885) | GeoGreen Biofuels (81199) | California sourced Waste Oil (Used Cooking Oil)Biodiesel produced in California (Provisional) | None | Retired |
| T1N-1545 | Tier 1 | 2.0 | Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG | Ohio | Landfill Gas | Compressed Natural Gas | None | None | CNGLF240 | 58.21 | 11/2/2016 | None | Bio-CNG | Athens Services (A431) | Irwindale (V5355) | Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG | None | Retired |
| T1N-1704 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona | Arizona | North American NG | Liquefied Natural Gas | None | None | LNGF202 | 91.03 | 7/10/2017 | None | Fossil LNG | Clean Energy (5481) | Ehrenberg LNG (C0660) | North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona | None | Retired |
| T1N-1705 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; re-gasified to L-CNG in California | Arizona | North American NG | Liquefied Compressed Natural Gas | None | None | CNGF207 | 93.59 | 7/10/2017 | None | Fossil CNG | Clean Energy (5481) | Ehrenberg LNG (C0660) | North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; regasified to LCNG in California | None | Retired |
| T1N-1707 | Tier 1 | 2.0 | Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California | Iowa | Used Cooking Oil | Biodiesel | None | None | BDU223 | 22.50 | 3/17/2017 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California | None | Retired |
| T1N-1708 | Tier 1 | 2.0 | Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California | Iowa | Corn Oil | Biodiesel | None | None | BDC208 | 34.10 | 3/17/2017 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | US sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California | None | Retired |
| T1N-1711 | Tier 1 | 2.0 | Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): CA-sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)** | California | Used Cooking Oil | Biodiesel | None | None | BDU220 | 20.96 | 1/27/2017 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | CAsourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional) | None | Retired |
| T1N-1089 | Tier 1 | 2.0 | Fuel Producer: Heartland Corn Products (4827) Facility Name: Heartland Corn Products (70089). Midwest Corn, Ethanol, Dry Mill, DDGS, NG | Minnesota | Corn | Ethanol | None | None | ETHC204 | 80.24 | 3/31/2016 | None | Ethanol | Heartland Corn Products (4827) | Heartland Corn Products (70089) | Midwest Corn, Ethanol, Dry Mill, DDGS, NG | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1721 | Tier 1 | 2.0 | Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Pantaleon), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and electricity co-product credit | Guatemala | Molasses | Ethanol | None | None | ETHM231 | 40.20 | 5/19/2017 | None | Ethanol | Bio Etanol, SA (5834) | Bio Etanol (Pantaleon), SA (71037) | Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and electricity coproduct credit | None | Retired |
| T1N-1722 | Tier 1 | 2.0 | Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Concepcion), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and co-product credit for surplus electricity export, and mechanized harvesting | Guatemala | Molasses | Ethanol | None | None | ETHM232 | 41.93 | 5/19/2017 | None | Ethanol | Bio Etanol, SA (5834) | Bio Etanol (Concepcion), SA (71037) | Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and coproduct credit for surplus electricity export, and mechanized harvesting | None | Retired |
| T1N-1733 | Tier 1 | 2.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California | Texas | Used Cooking Oil (UCO) | Biodiesel | BDU227 | 20.83 | BDU227R | 22.45 | 11/28/2018 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California | None | Retired |
| T1N-1735 | Tier 1 | 2.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California | Texas | Used Cooking Oil (UCO) | Biodiesel | BDU225 | 28.54 | BDU225R | 30.15 | 11/28/2018 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California | None | Retired |
| T1N-1736 | Tier 1 | 2.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California | Texas | Soybean Oil | Biodiesel | BDS210 | 51.94 | BDS210R | 53.43 | 11/28/2018 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California | None | Retired |
| T1N-1571 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS | Kansas | Sorghum | Ethanol | None | None | ETHG216 | 80.38 | 2/2/2017 | None | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS | None | Retired |
| T1N-1742 | Tier 1 | 2.0 | Fuel Producer: Lakeview Biodiesel, LLC (L430) Facility Name: Lakeview Biodiesel, LLC (W0607): Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California **(Provisional)** | Missouri | Soybean | Biodiesel | None | None | BDS212 | 56.20 | 6/30/2017 | None | Biodiesel | Lakeview Biodiesel, LLC (L430) | Lakeview Biodiesel, LLC (W0607) | Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California (Provisional) | None | Retired |
| T1N-1568 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS | Kansas | Corn | Ethanol | None | None | ETHC282 | 80.85 | 2/2/2017 | None | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS | None | Retired |
| T1N-1751 | Tier 1 | 2.0 | Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): High energy rendered Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California**(Provisional)** | California | Used Cooking Oil | Biodiesel | None | None | BDU230 | 21.53 | 6/28/2017 | None | Biodiesel | BUSTER BIOFUELS LLC (4166) | BUSTER BIOFUELS LLC (83449) | High energy rendered Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California(Provisional) | None | Retired |
| T1R-1241 | Tier 1 | 2.0 | Fuel Producer: Green Plains Holdings II LLC - Lakota (4755) Facility Name: Green Plains Holdings II LLC - Lakota (70051). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC024 | 91.60 | ETHC256L | 81.42 | 3/31/2016 | None | Ethanol | Green Plains Holdings II LLC Lakota (4755) | Green Plains Holdings II LLC Lakota (70051) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1113 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA | Ohio | Landfill Gas | Compressed Natural Gas | CNG025 | 28.68 | CNGLF209L | 60.92 | 9/30/2016 | None | Bio-CNG | Clean Energy (5481) | LES Renewable NG, LLC SWACO Facility (71157) | Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA | None | Retired |
| T2R-1067 | Tier 2 | 2.0 | Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: Archer Daniels Midland Compnay - Columbus Dry Mill (70355). Midwest, Corn Ethanol, Dry Mill, NG, Closed-loop heat recovery, Cogeneration | Nebraska | Corn | Ethanol | ETHC018_2 | 87.11 | ETHC274L | 81.47 | 3/31/2016 | None | Ethanol | Archer Daniels Midland Co (4888) | Archer Daniels Midland Compnay Columbus Dry Mill (70355) | Midwest, Corn Ethanol, Dry Mill, NG, Closedloop heat recovery, Cogeneration | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1234 | Tier 1 | 2.0 | Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | North Dakota | Corn | Ethanol | None | None | ETHC218 | 82.30 | 3/31/2016 | None | Ethanol | Red Trail Energy LLC (4803) | Red Trail Energy LLC (70077) | Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T1N-1506 | Tier 1 | 2.0 | Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG | South Dakota | Sorghum | Ethanol | None | None | ETHG214 | 85.72 | 11/2/2016 | None | Ethanol | NuGen Energy, LLC (3332) | NuGen Energy, LLC (70195) | Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG | None | Retired |
| T1N-1143 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Bonfim (70548) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM216 | 44.24 | 6/6/2016 | None | Ethanol | Raízen Energia S/A (3805) | Bonfim (70548) | Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1570 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS | Kansas | Sorghum | Ethanol | None | None | ETHG217 | 88.90 | 2/2/2017 | None | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS | None | Retired |
| T1N-1191 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS207 | 46.24 | 6/6/2016 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483) | Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1491 | Tier 1 | 2.0 | Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California | Texas | Tallow | Biodiesel | None | None | BDT217 | 38.27 | 3/22/2017 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California | None | Retired |
| T1N-1492 | Tier 1 | 2.0 | Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California | Texas | Soybean | Biodiesel | None | None | BDS209 | 58.55 | 3/22/2017 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California | None | Retired |
| T1N-1493 | Tier 1 | 2.0 | Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California | Texas | Used Cooking Oil | Biodiesel | None | None | BDU224 | 28.40 | 3/22/2017 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California | None | Retired |
| T1N-1617 | Tier 1 | 2.0 | Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California | Iowa | Tallow | Biodiesel | None | None | BDT212 | 35.94 | 2/2/2017 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | US sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California | None | Retired |
| T2N-1116 | Tier 2 | 2.0 | Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Self-rendered Used Cooking Oil Biodiesel Produced in California **(Provisional)** | San Diego, California | Used Cooking Oil | Biodiesel | None | None | BDU202 | 8.63 | 4/1/2016 | None | Biodiesel | New Leaf Biofuel (7768) | New Leaf Biofuel (83541) | Selfrendered Used Cooking Oil Biodiesel Produced in California (Provisional) | None | Retired |
| T2N-1154 | Tier 2 | 2.0 | Fuel Producer: Biodico Westside (6231) Facility Name: Biodico Plant (83027): California Used Cooking Oil; Biodiesel produced in Five Points, California **(Provisional)** | California | Used Cooking Oil | Biodiesel | None | None | BDU229 | 14.97 | 6/1/2017 | Pathway Details (PDF) | Biodiesel | Biodico Westside (6231) | Biodico Plant (83027) | California Used Cooking Oil; Biodiesel produced in Five Points, California (Provisional) | None | Retired |
| T2N-1159 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed on-site | California | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF217 | 7.39 | 6/22/2017 | Pathway Details (PDF) | Bio-LNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed onsite | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1162 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck | California | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF218 | 7.74 | 6/22/2017 | Pathway Details (PDF) | Bio-LNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck | None | Retired |
| T1N-1630 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified to L-CNG in California | Michigan | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF244 | 67.29 | 7/10/2017 | None | Bio-CNG | Clean Energy (5481) | Canton Renewables (71041) | Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified to LCNG in California | None | Retired |
| T2N-1164 | Tier 2 | 2.0 | Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck | California | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF219 | 10.71 | 6/22/2017 | Pathway Details (PDF) | Bio-LNG | High Mountain Fuels, LLC (4293) | Altamont BioLNG Plant (70526) | Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck | None | Retired |
| T1N-1485 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM235 | 47.56 | 8/17/2017 | None | Ethanol | Copersucar (3702) | Pioneiros Bioenergia SA (70430) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T2N-1192 | Tier 2 | 2.0 | Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): Raw Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California **(Provisional)** | California | Used Cooking Oil | Biodiesel | None | None | BDU231 | 16.90 | 7/10/2017 | Pathway Details (PDF) | Biodiesel | BUSTER BIOFUELS LLC (4166) | BUSTER BIOFUELS LLC (83449) | Raw Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California (Provisional) | None | Retired |
| T1N-1627 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California | Michigan | Landfill Gas | Liquefied Natural Gas | LNGLF221 | 66.93 | LNGLF221R | 72.42 | 8/16/2017 | None | Bio-LNG | Clean Energy (5481) | Canton Renewables (71041) | Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California | None | Retired |
| T1N-1628 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; re-gassified to L-CNG in California | Michigan | Landfill Gas | Liquefied Compressed Natural Gas | CNGLF255 | 69.48 | CNGLF255R | 74.97 | 8/16/2017 | None | Bio-CNG | Clean Energy (5481) | Canton Renewables (71041) | Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; regassified to LCNG in California | None | Retired |
| T1N-1651 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Louisiana | Landfill Gas | Compressed Natural Gas | None | None | CNGLF260 | 39.31 | 8/24/2017 | None | Bio-CNG | Shell Energy North America (6154) | JDP Renewables (L6161) | Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1654 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | Louisiana | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF224 | 47.28 | 8/24/2017 | None | Bio-LNG | Shell Energy North America (6154) | JDP Renewables (L6161) | Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | None | Retired |
| T1N-1655 | Tier 1 | 2.0 | Shell Energy North America (6154); JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional) | Louisiana | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF259 | 49.82 | 8/24/2017 | None | Bio-CNG | Shell Energy North America (6154) | JDP Renewables (L6161) | Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional) | None | Retired |
| T1N-1659 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwood Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | Texas | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF223 | 46.60 | 8/24/2017 | None | Bio-LNG | Shell Energy North America (6154) | East Texas Renewables (F2942) | Greenwood Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | None | Retired |
| T1N-1660 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwodd Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional) | Texas | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF258 | 49.15 | 8/24/2017 | None | Bio-LNG | Shell Energy North America (6154) | East Texas Renewables (F2942) | Greenwodd Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1664 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | Arkansas | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF222 | 50.15 | 8/24/2017 | None | Bio-LNG | Shell Energy North America (6154) | Cambrian Energy/Southtex Fort Smith Treaters (C5950) | Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional) | None | Retired |
| T1N-1665 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified and compressed in California (Provisional) | Arkansas | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF257 | 52.70 | 8/24/2017 | None | Bio-CNG | Shell Energy North America (6154) | Cambrian Energy/Southtex Fort Smith Treaters (C5950) | Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified and compressed in California (Provisional) | None | Retired |
| T1N-1782 | Tier 1 | 2.0 | Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool - Batatais Unit (70408); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS236 | 48.71 | 8/17/2017 | None | Ethanol | Usina Batatais S/A Açúcar e Álcool (6446) | Usina Batatais SA Açucar e Álcool Batatais Unit (70408) | Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1784 | Tier 1 | 2.0 | Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool (70409); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS235 | 47.53 | 8/17/2017 | None | Ethanol | Usina Batatais S/A Açúcar e Álcool (6446) | Usina Batatais SA Açucar e Álcool (70409) | Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1787 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Costa Pinto (70552): Raizen Energia S.A., COPI: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM219 | 44.19 | ETHM219R | 47.02 | 8/9/2017 | Former T1N-1566, FPC: ETHM219 | Ethanol | Raízen Energia S/A (3805) | Costa Pinto (70552) | Raizen Energia SA, COPI Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1R-1788 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Raizen Energia S.A., Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane -to-ethanol, with credit for mechanized harvesting | Brazil | Sugarcane | Ethanol | ETHS221 | 46.07 | ETHS221R | 46.91 | 8/9/2017 | Former T1N-1210, FPC: ETHS221 | Ethanol | Raízen Energia S/A (3805) | Gasa (70551) | Raizen Energia SA, Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane toethanol, with credit for mechanized harvesting | None | Retired |
| T1R-1789 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Rafard (70557): Raizen Energia S.A., Rafard Mill: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM215 | 47.17 | ETHM215R | 48.76 | 8/9/2017 | Former T1N-1140, FPC: ETHM215 | Ethanol | Raízen Energia S/A (3805) | Rafard (70557) | Raizen Energia SA, Rafard Mill; Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1R-1790 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Paraguaçu (71057): Raizen Energia S.A., Paraguacu Mill, Sao Paulo, Brazil: Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM223 | 46.71 | ETHM223R | 49.32 | 8/9/2017 | Former T1N-1146, FPC:ETHM223 | Ethanol | Raízen Energia S/A (3805) | Paraguaçu (71057) | Raizen Energia SA, Paraguacu Mill, Sao Paulo, Brazil; Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1771 | Tier 1 | 2.0 | Fuel Producer: EM Gas Marketing, LLC (6287); Facility Name: Fresh Kills Landfill EMGM (7120t); Fresh Kills landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California | New York | Landfill Gas | Compressed Natural Gas | None | None | CNGLF262 | 37.13 | 8/29/2017 | None | Bio-CNG | EM Gas Marketing, LLC (6287) | Fresh Kills Landfill EMGM (7120t) | Fresh Kills landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California | None | Retired |
| T1N-1775 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Meadow Branch landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional) | Tennessee | Landfill Gas | CNG | CNGLF261 | 38.51 | CNGLF261R | 52.14 | 5/11/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Meadow Branch Landfill Gas Processing Facility (71252) | Meadow Branch landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional) | None | Retired |
| T1N-1755 | Tier 1 | 2.0 | Fuel Producer: REG New Boston, LLC (6067); Facility Name: REG New Boston, LLC (81490); High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California | Texas | Used Cooking Oil | Biodiesel | None | None | BDU232 | 20.23 | 8/31/2017 | None | Biodiesel | REG New Boston, LLC (6067) | REG New Boston, LLC (81490) | High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California | None | Retired |
| T2N-1191 | Tier 2 | 2.0 | Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Tier 2 Method 2B Pathway: Ethanol derived from recycled beverages in Rancho Cucamonga, California | California | Waste Beverage | Ethanol | None | None | ETHWB201 | 69.82 | 9/1/2017 | Application Package | Ethanol | USL Parallel Products of California (4018) | USL Parallel Products of California (70122) | Tier 2 Method 2B Pathway Ethanol derived from recycled beverages in Rancho Cucamonga, California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1693 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Lúcia (70426); Brazilian sugarcane juice-to-ethanol pathway, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS241 | 46.88 | 9/1/2017 | None | Ethanol | Copersucar (3702) | Usina Santa Lúcia (70426) | Brazilian sugarcane juicetoethanol pathway, with credit for mechanized harvesting | None | Retired |
| T1N-1643 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations | Ohio | Landfill Gas | Compressed Natural Gas | None | None | CNGLF264 | 43.97 | 9/5/2017 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | WM Renewable Energy of Ohio American Landfill (71222) | American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations | None | Retired |
| T1N-1754 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified in CA | Ohio | Landfill Gas | Liquefied Compressed Natural Gas | None | None | CNGLF263 | 59.12 | 9/5/2017 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | WM Renewable Energy of Ohio American Landfill (71222) | American landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified in CA | None | Retired |
| T1N-1477 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane molases-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM205L | T1R-1259 | ETHM239 | 48.90 | 9/5/2017 | None | Ethanol | Copersucar (3702) | Usina Barra Grande de Lençóis SA (70412) | Brazilian sugarcane molasestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1753 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional) | Ohio | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF225 | 56.57 | 9/5/2017 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | WM Renewable Energy of Ohio American Landfill (71222) | American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional) | None | Retired |
| T2N-1197 | Tier 2 | 2.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional) | Louisiana | Used Cooking Oil | Renewable Diesel | None | None | RDU203 | 24.35 | 9/11/2017 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Tier 2 Method 2B Pathway Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional) | None | Retired |
| T2N-1198 | Tier 2 | 2.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Non-Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional) | Louisiana | Used Cooking Oil | Renewable Diesel | None | None | RDU204 | 18.99 | 9/11/2017 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Tier 2 Method 2B Pathway Renewable Diesel produced from NonRendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional) | None | Retired |
| T2N-1199 | Tier 2 | 2.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional) | Louisiana | Corn Oil | Renewable Diesel | None | None | RDC202 | 34.32 | 9/11/2017 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Tier 2 Method 2B Pathway Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional) | None | Retired |
| T2N-1200 | Tier 2 | 2.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Tallow, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional) | Louisiana | Tallow | Renewable Diesel | None | None | RDT206 | 35.71 | 9/11/2017 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Tier 2 Method 2B Pathway Renewable Diesel produced from Tallow, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional) | None | Retired |
| T2N-1201 | Tier 2 | 2.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional) | Louisiana | Soybean Oil | Renewable Diesel | None | None | RDS201 | 56.57 | 9/11/2017 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Tier 2 Method 2B Pathway Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional) | None | Retired |
| T1N-1478 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS242 | 48.86 | 9/19/2017 | None | Ethanol | Copersucar (3702) | Açucareira Quatá SA (70406) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1479 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM207L | 45.97 | ETHM240 | 50.69 | 9/19/2017 | None | Ethanol | Copersucar (3702) | Açucareira Quatá SA (70406) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1472 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS243 | 47.53 | 9/25/2017 | None | Ethanol | Copersucar (3702) | Usina Cerradão Ltda (70425) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1473 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM212L | 44.6 | ETHM241 | 48.80 | 9/25/2017 | None | Ethanol | Copersucar (3702) | Usina Cerradão Ltda (70425) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1474 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | ETHS205L | 45.21 | ETHS244 | 45.07 | 9/25/2017 | None | Ethanol | Copersucar (3702) | Açúcareira Zillo Lorenzetti SA (70432) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1475 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM206L | 46.32 | ETHM242 | 46.26 | 9/25/2017 | None | Ethanol | Copersucar (3702) | Açúcareira Zillo Lorenzetti SA (70432) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1757 | Tier 1 | 2.0 | Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490); U.S. sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California | Texas | Tallow | Biodiesel | None | None | BDT218 | 34.27 | 9/25/2017 | None | Biodiesel | REG New Boston, LLC (6067) | REG New Boston, LLC (81490) | US sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California | None | Retired |
| T2N-1227 | Tier 2 | 2.0 | Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG | Kansas | Wheat Starch Slurry | Ethanol | None | None | ETHWSS200 | 45.20 | 10/11/2017 | Application Package | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG | None | Retired |
| T2N-1228 | Tier 2 | 2.0 | Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG | Kansas | Wheat Starch Slurry | Ethanol | None | None | ETHWSS201 | 53.73 | 10/11/2017 | Application Package | Ethanol | White Energy, Inc. (4745) | US Energy Partners, LLC (White Energy, Russell)(70038) | Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG | None | Retired |
| T2N-1190 | Tier 2 | 2.0 | Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps. (Provisional) | California | North American NG | Hydrogen | None | None | HYGFCR200 | 165.88 | 10/13/2017 | Application Package | Hydrogen | Linde LLC (L012) | Linde Canada LH2 Plant (R1980) | Tier 2 Method 2B Pathway Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps (Provisional) | None | Retired |
| T1N-1192 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483); Brazilian sugarcane molasses-to-ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM246 | 46.78 | 11/6/2017 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483) | Brazilian sugarcane molassestoethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1190 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579); Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM245 | 48.32 | 11/6/2017 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | USINA FRUTAL AÇÚCAR E ÁLCOOL (70579) | Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1188 | Tier 1 | 2.0 | Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM244 | 48.60 | 11/6/2017 | None | Ethanol | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | BUNGE ACUCAR E BIOENERGIA LTDA (3858) | Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1074 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export. | Brazil | Sugarcane | Ethanol | None | None | ETHS245 | 47.72 | 11/6/2017 | None | Ethanol | BIOSEV SA (3869) | Usina Cresciumal (71068) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1075 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS246 | 50.16 | 11/6/2017 | None | Ethanol | BIOSEV SA (3869) | Usina Santa Elisa (71070) | Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1076 | Tier 1 | 2.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Vale do Rosário (70440); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS247 | 52.07 | 11/6/2017 | None | Ethanol | BIOSEV SA (3869) | Usina Vale do Rosário (70440) | Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting | None | Retired |
| T1N-1171 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS248 | 46.16 | 11/6/2017 | None | Ethanol | Raízen Energia S/A (3805) | Araraquara (71055) | Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting | None | Retired |
| T1N-1136 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | None | None | ETHM243 | 47.63 | 11/6/2017 | None | Ethanol | Raízen Energia S/A (3805) | Araraquara (71055) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1786 | Tier 1 | 2.0 | Fuel Producer: Show Me Ethanol, LLC (7464); Facility Name: Show Me Ethanol (70300); Dry mill corn ethanol with co-production of DDGS, MDGS, and Corn Oil using natural gas and electricity power. | Missouri | Corn | Ethanol | None | None | ETHC294 | 77.26 | 12/21/2017 | None | Ethanol | Show Me Ethanol, LLC (7464) | Show Me Ethanol (70300) | Dry mill corn ethanol with coproduction of DDGS, MDGS, and Corn Oil using natural gas and electricity power | None | Retired |
| T1N-1785 | Tier 1 | 2.0 | Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional) | Iowa | Corn | Ethanol | None | None | ETHC292 | 73.11 | 12/21/2017 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Dry mill corn ethanol with coproduction of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional) | None | Retired |
| T1N-1470 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS249 | 47.66 | 11/29/2017 | None | Ethanol | Copersucar (3702) | Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1471 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting. | Brazil | Molasses | Ethanol | ETHM209L | 46.04 | ETHM247 | 48.41 | 11/29/2017 | None | Ethanol | Copersucar (3702) | Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419) | Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1637 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ | Ohio | Landfill Gas | Liquefied Natural Gas | None | None | LNGLF227 | 64.62 | 12/21/2017 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | GSF Energy Rumpke Landfill (71138) | Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ | None | Retired |
| T1N-1638 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA | Ohio | Landfill Gas | Compressed Natural Gas | None | None | CNGLF268 | 67.17 | 12/21/2017 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | GSF Energy Rumpke Landfill (71138) | Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; regasified in CA | None | Retired |
| T1N-1634 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations | Ohio | Landfill Gas | Compressed Natural Gas | None | None | CNGLF265 | 52.32 | 12/1/2017 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | GSF Energy Rumpke Landfill (71138) | Rumpke landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations | None | Retired |
| T2N-1195 | Tier 2 | 2.0 | Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California. | Texas | Used Cooking Oil | Biodiesel | None | None | BDU237 | 14.75 | 1/8/2018 | Application Package | Biodiesel | REG New Boston, LLC (6067) | REG New Boston, LLC (81490) | Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1208 | Tier 2 | 2.0 | Fuel Producer: 3 Phases Renewables Inc. (P306) ; Facility Name: 3PR (P1225): Solar-based (Photovoltaic) Electricity for a Single Dual Port Electric Vehicle Charging Station. | California | Solar or Wind | Electricity | None | None | ELCR200 | 0.00 | 1/26/2018 | Application Package | Electricity | 3 Phases Renewables Inc (P306) | 3PR (P1225) | Solarbased (Photovoltaic)Electricity for a Single Dual Port Electric Vehicle Charging Station | None | Retired |
| T2N-1166 | Tier 2 | 2.0 | Fuel Producer: REG Newton, LLC (3514) ; Facility Name: REG Newton, LLC (80162): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California. | Iowa | Used Cooking Oil | Biodiesel | None | None | BDU235 | 15.49 | 1/8/2018 | Application Package | Biodiesel | REG Newton, LLC (3514) ; | REG Newton, LLC (80162) | Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California | None | Retired |
| T2N-1158 | Tier 2 | 2.0 | Fuel Producer: FirstElement Fuel (E426): North American fossil NG to Hydrogen (H2) gas production by Steam Reforming of methane via pipeline to California then liquefied, re-gasified, and trucked to multiple H2 dispensing locations | California | North American Natural Gas | Hydrogen | None | None | HYGN001_2 | 151.01 | 4/5/2017 | None | Hydrogen | FirstElement Fuel (E426) | North American fossil NG to Hydrogen (H2) | gas production by Steam Reforming of methane via pipeline to California then liquefied, regasified, and trucked to multiple H2 dispensing locations | None | Retired |
| T2N-1233 | Tier 2 | 2.0 | Fuel Producer: JC Chemical Co., Ltd. (6094) ; Facility Name: JC Chemical Co., Ltd. (81585); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California | Korea, South | Used Cooking Oil | Biodiesel | None | None | BDU238 | 20.15 | 3/1/2018 | Application Package | Biodiesel | JC Chemical Co Ltd (6094) | JC Chemical Co Ltd (81585) | Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California | None | Retired |
| T2N-1216 | Tier 2 | 2.0 | Fuel Producer: General Biodiesel Seattle, LLC (3367); Facility Name: General Biodiesel Seattle, LLC (80086); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced Used Cooking Oil (UCO). Fuel produced in Seattle, Washington and transported by rail to California (Provisional) | Washington | Used Cooking Oil | Biodiesel | None | None | BDU239 | 28.81 | 3/7/2018 | Application Package | Biodiesel | General Biodiesel Seattle, LLC (3367) | General Biodiesel Seattle, LLC (80086) | Tier 2 Method 2B Pathway Biodiesel produced from US sourced Used Cooking Oil (UCO)Fuel produced in Seattle, Washington and transported by rail to California (Provisional) | None | Retired |
| T1N-1476 | Tier 1 | 2.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting | Brazil | Sugarcane | Ethanol | None | None | ETHS250 | 47.71 | 3/13/2018 | None | Ethanol | Copersucar (3702) | Usina Barra Grande de Lençóis SA (70412) | Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting | None | Retired |
| T1N-1761 | Tier 1 | 2.0 | Fuel Producer: Dakota Spirit AgEnergy (6286) Facility Name: Dakota Spirit AgEnergy (71202): Corn Ethanol, Dry Mill, Midwest, Steam, NG | North Dakota | Corn | Ethanol | None | None | ETHC288 | 69.47 | 7/5/2017 | None | Ethanol | Dakota Spirit AgEnergy (6286) | Dakota Spirit AgEnergy (71202) | Corn Ethanol, Dry Mill, Midwest, Steam, NG | None | Retired |
| T1N-1210 | Tier 1 | 2.0 | Fuel Producer: Raízen Energia S/A (3805) Facility Name: Gasa (70551). Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting. | Brazil | Sugarcane | Ethanol | None | None | ETHS221 | 46.07 | 12/20/2016 | None | Ethanol | Raízen Energia S/A (3805) | Gasa (70551) | Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting | None | Retired |
| T1N-1382 | Tier 1 | 2.0 | Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore | Singapore | Tallow | Renewable Diesel | None | None | RDT202 | 39.06 | 7/1/2016 | None | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore | None | Retired |
| T2N-1012 | Tier 2 | 2.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066) (provisional); Tier 2 Method 2B Pathway: Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional) | California | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU240 | 19.00 | 3/29/2018 | Application Package | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Tier 2 Method 2B Pathway Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional) | None | Retired |
| T2N-1229 | Tier 2 | 2.0 | Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional) | Oregon | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU241 | 18.43 | 3/29/2018 | Application Package | Biodiesel | SeQuential Pacific Biodiesel LLC (6129) | SeQuentialPacific Biodiesel, LLC(83525) | Tier 2 Method 2B Pathway Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO)Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional) | None | Retired |
| T1N-1768 | Tier 1 | 2.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California | Illinois | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU242 | 21.84 | 4/2/2018 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1770 | Tier 1 | 2.0 | Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); U.S. sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California | Illinois | Tallow & Animal Fat | Biodiesel | None | None | BDT219 | 35.79 | 4/2/2018 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | US sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California | None | Retired |
| T2N-1242 | Tier 2 | 2.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953) ; Facility Name: Dansuk Industrial Co., Ltd (81302); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Shiheung-City, South Korea and transported by ocean tanker to California | South Korea | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU243 | 27.00 | 4/9/2018 | Application Package | Biodiesel | Dansuk Industrial Co Ltd (5953) | Dansuk Industrial Co Ltd (81302) | Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in ShiheungCity, South Korea and transported by ocean tanker to California | None | Retired |
| T1N-1621 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas (TN) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | Tennessee | Landfill Gas | CNG | CNGLF250 | 54.87 | CNGLF250R | 55.00 | 4/25/2018 | None | Bio-CNG | Clean Energy (5481) | CERF Shelby LLC (71163)(Provisional) | North Shelby landfill gas (TN)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California | None | Retired |
| T1N-1624 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona | California | Landfill Gas | LNG | LNGLF220 | 62.18 | LNGLF220R | 62.30 | 4/25/2018 | None | Bio-LNG | Clean Energy (5481) | CERF Shelby LLC (71163) | North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona | None | Retired |
| T1N-1625 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified in California | California | Landfill Gas - L-CNG | CNG | CNGLF253 | 64.71 | CNGLF253R | 64.85 | 4/25/2018 | None | Bio-CNG | Clean Energy (5481) | CERF Shelby LLC (71163)(Provisional) | North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified in California | None | Retired |
| T1N-1812 | Tier 1 | 2.0 | Fuel Producer: Victor Valley Transit Authority (V056) ; Facility Name: River Birch Landfill (R7407); River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Texas | Landfill Gas | CNG | CNGLF269 | 40.73 | CNGLF269R | 44.33 | 2/6/2019 | None | Bio-CNG | Victor Valley Transit Authority (V056) | River Birch Landfill (R7407) | River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T2N-1250 | Tier 2 | 2.0 | Fuel Producer: Apple (A449) ; Facility Name: VP02 (V8866); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional) | California | Solar or Wind | Electricity | None | None | ELCR201 | 0.00 | 5/4/2018 | Application Package | Electricity | Apple (A449) | VP02 (V8866) | Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional) | None | Retired |
| T2N-1251 | Tier 2 | 2.0 | Fuel Producer: Apple (A449) ; Facility Name: HS01 (H3518); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional) | California | Solar or Wind | Electricity | None | None | ELCR202 | 0.00 | 5/4/2018 | Application Package | Electricity | Apple (A449) | HS01 (H3518) | Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional) | None | Retired |
| T1N-1822 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154) ; Facility Name: Pine Hill Renewables, LLC (71288); Pine Hill landfill gas in Kilgore, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Texas | Landfill Gas | CNG | None | None | CNGLF272 | 39.83 | 6/7/2018 | None | Bio-CNG | Shell Energy North America (6154) | Pine Hill Renewables, LLC (71288) | Pine Hill landfill gas in Kilgore, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T2N-1236 | Tier 2 | 2.0 | Fuel Producer: Adkins Energy LLC (4767) ; Facility Name: Adkins Energy, LLC (70070); Tier 2 Method 2B Pathway: Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional) | Illinois | Corn Oil | Biodiesel | None | None | BDC214 | 37.31 | 6/15/2018 | Application Package | Biodiesel | Adkins Energy LLC (4767) | Adkins Energy, LLC (70070) | Tier 2 Method 2B Pathway Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional) | None | Retired |
| T2N-1232 | Tier 2 | 2.0 | Fuel Producer: ASB Biodiesel Hong Kong (6347) ; Facility Name: ASB Biodiesel Hong Kong (83359); Tier 2 Method 2B Pathway: Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California | Hong Kong | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU245 | 27.80 | 6/21/2018 | Application Package | Biodiesel | ASB Biodiesel Hong Kong (6347) | ASB Biodiesel Hong Kong (83359) | Tier 2 Method 2B Pathway Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California | None | Retired |
| T2N-1202 | Tier 2 | 2.0 | Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California | Illinois | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU244 | 16.57 | 6/21/2018 | Application Package | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California | None | Retired |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1257 | Tier 2 | 2.0 | Fuel Producer: Albertsons Companies, Inc. (A505) ; Facility Name: Safeway Tracy Distribution Center (17814); Tier 2 Method 2B Pathway: Wind electricity for charging electric forklifts in Tracy, California (Provisional) | California | Solar or Wind | Electricity | None | None | ELCR203 | 0.00 | 6/21/2018 | Application Package | Electricity | Albertsons Companies, Inc (A505) | Safeway Tracy Distribution Center (17814) | Tier 2 Method 2B Pathway Wind electricity for charging electric forklifts in Tracy, California (Provisional) | None | Retired |
| T2N-1189 | Tier 2 | 2.0 | Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed Hydrogen from co-product hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps) and transported by truck to fueling stations in California (Provisional) | Canada | Sodium Chlorate Production Process | Hydrogen | None | None | HYGSC200 | 56.06 | 6/26/2018 | Application Package | Hydrogen | Linde LLC (L012) | Linde Canada LH2 Plant (R1980) | Tier 2 Method 2B Pathway Compressed Hydrogen from coproduct hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps)and transported by truck to fueling stations in California (Provisional) | None | Retired |
| T1N-1809 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Pennsylvania | Landfill Gas | CNG | None | None | CNGLF273 | 49.77 | 6/27/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy Shade (71134) | JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1781 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Southern Alleghenies (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Pennsylvania | Landfill Gas | CNG | None | None | CNGLF274 | 58.84 | 6/27/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy Southern Alleghenies (71133) | Southern Alleghenies (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1831 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Raeger (71131); Laurel Highlands (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Pennsylvania | Landfill Gas | CNG | None | None | CNGLF275 | 42.86 | 6/27/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy Raeger (71131) | Laurel Highlands (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T2N-1243 | Tier 2 | 2.0 | Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: U.S. sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California | Illinois | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU246 | 23.18 | 7/27/2018 | Application Package | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Tier 2 Method 2B Pathway US sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California | None | Retired |
| T2N-1247 | Tier 2 | 2.0 | Fuel Producer: Southwest Iowa Renewable Energy (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Tier 2 Method 2B Pathway: Midwest, dry mill, corn ethanol produced using coal-derived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California | Iowa | Corn | Ethanol | None | None | ETHC298 | 79.79 | 8/2/2018 | Application Package | Ethanol | Southwest Iowa Renewable Energy (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Tier 2 Method 2B Pathway Midwest, dry mill, corn ethanol produced using coalderived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California | None | Retired |
| T1N-1835 | Tier 1 | 2.0 | Fuel Producer: Ag Processing Inc (4552) ; Facility Name: AGP Methyl Ester (St Joseph) (81732); Biodiesel produced from Soybean Oil (self-extraction) in St. Joseph, Missouri and transported by rail to California. | Missouri | Soybean Oil | Biodiesel | None | None | BDS213 | 50.48 | 8/27/2018 | None | Biodiesel | Ag Processing Inc (4552) | AGP Methyl Ester (St Joseph)(81732) | Biodiesel produced from Soybean Oil (selfextraction)in St Joseph, Missouri and transported by rail to California | None | Retired |
| T1N-1855 | Tier 1 | 2.0 | Fuel Producer: Ag Processing Inc (4552) ; Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (self-extraction) and transported by rail to California. | Iowa | Soybean Oil | Biodiesel | None | None | BDS214 | 50.03 | 8/27/2018 | None | Biodiesel | Ag Processing Inc (4552) | Ag Processing Inc Sgt Bluff (81733) | Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (selfextraction)and transported by rail to California | None | Retired |
| T2N-1249 | Tier 2 | 2.0 | Fuel Producer: Thumb BioEnergy (3862) ; Facility Name: Thumb BioEnergy (03862); Tier 2 Method 2B Pathway: Locally sourced, Self-Rendered Used Cooking Oil. Biodiesel produced in Sandusky, MI and transported by rail to California | Michigan | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU248 | 20.90 | 9/20/2018 | Application Package | Biodiesel | Thumb BioEnergy (3862) | Thumb BioEnergy (03862) | Tier 2 Method 2B Pathway Locally sourced, SelfRendered Used Cooking Oil;Biodiesel produced in Sandusky, MI and transported by rail to California | None | Retired |
| T1N-1851 | Tier 1 | 2.0 | Fuel Producer: Solfuels USA LLC (S357) ; Facility Name: Solfuels USA LLC (82892); Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional) | Arkansas | Soybean Oil | Biodiesel | None | None | BDS215 | 55.10 | 9/20/2018 | None | Biodiesel | Solfuels USA LLC (S357) | Solfuels USA LLC (82892) | Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional) | None | Retired |
| T1N-1861 | Tier 1 | 2.0 | Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional) | Illinois | Tallow & Animal Fat | Biodiesel | None | None | BDT220 | 36.80 | 9/20/2018 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | US sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1862 | Tier 1 | 2.0 | Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional) | Illinois | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU249 | 22.58 | 9/20/2018 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional) | None | Retired |
| T1N-1860 | Tier 1 | 2.0 | Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional) | Illinois | Corn Oil | Biodiesel | None | None | BDC215 | 35.13 | 9/20/2018 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | US sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional) | None | Retired |
| T1N-1864 | Tier 1 | 2.0 | Fuel Producer: Shell Energy North America (6154) ; Facility Name: Melissa Renewables, LLC (71407); Melissa landfill gas in Melissa, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Texas | Landfill Gas | Compressed Natural Gas | None | None | CNGLF276 | 40.63 | 9/24/2018 | None | Bio-CNG | Shell Energy North America (6154) | Melissa Renewables, LLC (71407) | Melissa landfill gas in Melissa, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1811 | Tier 1 | 2.0 | Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | California | Landfill Gas | CNG | None | None | CNGLF277 | 32.28 | 10/3/2018 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | EBI Energie In (71254) | EBI landfill gas in SaintThomas, Quebec to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1863 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Charleston Landfill Gas Processing Facility (71314); Landfill gas in Charleston, West Virginia to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | West Virginia | Landfill Gas | CNG | None | None | CNGLF278 | 66.55 | 10/9/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Charleston Landfill Gas Processing Facility (71314) | Landfill gas in Charleston, West Virginia to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T1N-1832 | Tier 1 | 2.0 | Fuel Producer: Imperial Western Products (9871) ; Facility Name: Imperial Western Products (81066); U.S. sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional) | California | Tallow & Animal Fat | Biodiesel | None | None | BDT221 | 38.36 | 10/15/2018 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | US sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional) | None | Retired |
| T2N-1275 | Tier 2 | 2.0 | Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional) | Illinois | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU250 | 17.33 | 10/23/2018 | Application Package | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional) | None | Retired |
| T1N-1837 | Tier 1 | 2.0 | Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn | Ethanol | None | None | ETHC306 | 81.86 | 12/4/2018 | None | Ethanol | POET Biorefining Big Stone (4736) | POET Biorefining Big Stone (70025) | Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1259 | Tier 2 | 2.0 | Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Kernel Fiber | Ethanol | None | None | ETHCF206 | 38.58 | 12/4/2018 | Application Package | Ethanol - Cellulosic | POET Biorefining Big Stone (4736) | POET Biorefining Big Stone (70025) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1268 | Tier 2 | 2.0 | Fuel Producer: Powerflex (P343) ; Facility Name: Mountain View HS (50381); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California | California | Solar or Wind | Electricity | None | None | ELCR205 | 0.00 | 12/11/2018 | Application Package | Electricity | Powerflex (P343) | Mountain View HS (50381) | Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California | None | Retired |
| T2N-1269 | Tier 2 | 2.0 | Fuel Producer: Powerflex (P343) ; Facility Name: Los Altos HS (45044); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California | California | Solar or Wind | Electricity | None | None | ELCR204 | 0.00 | 12/11/2018 | Application Package | Electricity | Powerflex (P343) | Los Altos HS (45044) | Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California | None | Retired |
| T2N-1278 | Tier 2 | 2.0 | Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional) | Arizona | Corn | Ethanol | None | None | ETHC312 | 38.06 | 12/18/2018 | Application Package | Ethanol | Pinal Energy LLC (4744) | Pinal Energy LLC (70136) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1248 | Tier 2 | 2.0 | Fuel Producer: California Renewable Power LLC (CARP) (C196) ; Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional) | California | HSAD Food & Green Waste | CNG | None | None | CNGGW201 | 0.34 | 12/20/2018 | Application Package | Bio-CNG | California Renewable Power LLC (CARP) (C196) | California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270) | Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional) | None | Retired |
| T1N-1865 | Tier 1 | 2.0 | Fuel Producer: W2Fuels (LVA Adrian Biofuel LLC) (3251) ; Facility Name: W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian) (81095); Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional) | Michigan | Soybean Oil | Biodiesel | None | None | BDS216 | 55.74 | 12/21/2018 | None | Biodiesel | W2Fuels (LVA Adrian Biofuel LLC)(3251) | W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian)(81095) | Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional) | None | Retired |
| T1N-1883 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Cambrian Energy (C5950S); Landfill gas from Fort Smith, Arkansas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Arkansas | Landfill Gas | CNG | None | None | CNGLF279 | 44.51 | 12/31/2018 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Cambrian Energy (C5950S) | Landfill gas from Fort Smith, Arkansas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| T2N-1239 | Tier 2 | 2.0 | Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California | Finland | Tallow & Animal Fat | Renewable Diesel | None | None | RDT208 | 45.08 | 1/16/2019 | Application Package | Renewable Diesel | Neste Renewable Fuels Oy (3734) | Neste Renewable Fuels Porvoo (80272) | Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California | None | Retired |
| T2N-1264 | Tier 2 | 2.0 | Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow. Shipped to Sluiskil Pre-treatment site. Fuel produced in Neste Porvoo Plant and transported to California (Provisional) | Finland | Tallow & Animal Fat | Renewable Diesel | None | None | RDT207 | 51.90 | 1/16/2019 | Application Package | Renewable Diesel | Neste Renewable Fuels Oy (3734) | Neste Renewable Fuels Porvoo (80272) | Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow Shipped to Sluiskil Pretreatment site; Fuel produced in Neste Porvoo Plant and transported to California (Provisional) | None | Retired |
| T2N-1289 | Tier 2 | 2.0 | Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional) | Finland | Used Cooking Oil (UCO) | Renewable Diesel | None | None | RDU205 | 30.97 | 1/16/2019 | Application Package | Renewable Diesel | Neste Renewable Fuels Oy (3734) | Neste Renewable Fuels Porvoo (80272) | Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional) | None | Retired |
| T2N-1246 | Tier 2 | 2.0 | Fuel Producer: Eco Solutions Co., Ltd (6266) ; Facility Name: Eco Solutions Co., Ltd (83159); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO) sourced in South Korea, Biodiesel produced in Jeongeup-si, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional) | South Korea | Used Cooking Oil (UCO) | Biodiesel | None | None | BDU251 | 22.31 | 3/18/2019 | Application Package | Biodiesel | Eco Solutions Co Ltd (6266) | Eco Solutions Co Ltd (83159) | Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO)sourced in South Korea, Biodiesel produced in Jeongeupsi, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional) | None | Retired |
| B001101 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B00110100 | -372.35 | 4/10/2019 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ruckman Farm (71256) | Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional) | None | Retired |
| B001102 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | Missouri | Swine Manure (044) | Liquefied Natural Gas (LNG) | None | None | LNG044B00110200 | -360.37 | 4/10/2019 | Application Package | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Ruckman Farm (71256) | Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | None | Retired |
| B001103 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and re-gasified in California (Provisional) | Missouri | Swine Manure (044) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN044B00110300 | -356.83 | 4/10/2019 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ruckman Farm (71256) | Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and regasified in California (Provisional) | None | Retired |
| A003301 | Tier 1 | 3.0 | Fuel Producer: CORN, LP (5065) ; Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California **(Provisional)** | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00330100 | 70.34 | 4/15/2019 | None | Ethanol | CORN, LP (5065) | CORN, LP (70145) | Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A001701 | Tier 1 | 3.0 | Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas | Nebraska | Corn (009) | Ethanol (ETH) | ETHC295 | 74.03 | ETH009A00170100 | 66.19 | 4/15/2019 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A004301 | Tier 1 | 3.0 | Fuel Producer: Kansas Ethanol, LLC (5810); Facility Name: Kansas Ethanol, LLC (70279); Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake **(Provisional)** | Kansas | Corn (009) | Ethanol (ETH) | ETHC299 | 67.83 | ETH009A00430100 | 62.79 | 4/15/2019 | None | Ethanol | Kansas Ethanol, LLC (5810) | Kansas Ethanol, LLC (70279) | Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake (Provisional) | None | Retired |
| A006801 | Tier 1 | 3.0 | Fuel Producer: Kansas Ethanol, LLC (5810) ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A00680100 | 67.59 | 4/15/2019 | None | Ethanol | Kansas Ethanol, LLC (5810) | Kansas Ethanol, LLC (70279) | Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional) | None | Retired |
| A006901 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754) ; Facility Name: Trenton Agri Products, LLC (70053; Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC210 | 69.75 | ETH009A00690100 | 65.13 | 4/16/2019 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053 | Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California | None | Retired |
| A008601 | Tier 1 | 3.0 | Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC229 | 67.43 | ETH009A00860100 | 62.37 | 4/16/2019 | None | Ethanol | Bridgeport Ethanol, LLC 5934; | Bridgeport Ethanol, LLC (70217) | Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California | None | Retired |
| A000701 | Tier 1 | 3.0 | Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC300 | 69.04 | ETH009A00070100 | 65.21 | 5/6/2019 | None | Ethanol | Great Plains Ethanol (4727) | Great Plains Ethanol, LLC (70012) | Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California | None | Retired |
| A000702 | Tier 1 | 3.0 | Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETHCF203 | 27.69 | ETH012A00070200 | 25.06 | 5/6/2019 | None | Ethanol - Cellulosic | Great Plains Ethanol (4727) | Great Plains Ethanol, LLC (70012) | Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California | None | Retired |
| A003401 | Tier 1 | 3.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC343 | 69.28 | ETH009A00340100 | 66.23 | 5/6/2019 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A003402 | Tier 1 | 3.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00340200 | 26.67 | 5/6/2019 | None | Ethanol - Cellulosic | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A003601 | Tier 1 | 3.0 | Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC313 | 71.98 | ETH009A00360100 | 67.09 | 5/6/2019 | None | Ethanol | Mid America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A003602 | Tier 1 | 3.0 | Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETHC311 | 38.12 | ETH012A00360200 | 32.40 | 5/6/2019 | None | Ethanol - Cellulosic | Mid America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A003701 | Tier 1 | 3.0 | Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC310 | 70.76 | ETH009A00370100 | 66.53 | 3/29/2019 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional) | None | Retired |
| A004101 | Tier 1 | 3.0 | Fuel Producer: Marquis Energy - Wisconsin LLC (5750) ; Facility Name: Marquis Energy - Wisconsin LLC (70269); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California | Wisconsin | Corn (009) | Ethanol (ETH) | None | None | ETH009A00410100 | 72.25 | 5/7/2019 | None | Ethanol | Marquis Energy Wisconsin LLC (5750) | Marquis Energy Wisconsin LLC (70269) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A004601 | Tier 1 | 3.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, on-site solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional) | California | Corn (009) | Ethanol (ETH) | ETHC207R | 72.94 | ETH009A00460100 | 66.76 | 3/29/2019 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Madera LLC (70061) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, onsite solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005101 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00510100 | 69.86 | 5/7/2019 | None | Ethanol | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005102 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00510200 | 30.32 | 5/7/2019 | None | Ethanol - Cellulosic | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005301 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00530100 | 73.81 | 5/6/2019 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005302 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00530200 | 66.94 | 5/6/2019 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005303 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00530300 | 26.95 | 5/6/2019 | None | Ethanol - Cellulosic | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00520100 | 75.97 | 5/6/2019 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00520200 | 68.75 | 5/6/2019 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00520300 | 28.78 | 5/6/2019 | None | Ethanol - Cellulosic | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005701 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00570100 | 76.25 | 5/6/2019 | None | Ethanol | POET Biorefining Ashton (4782) | POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005702 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00570200 | 67.07 | 5/6/2019 | None | Ethanol | POET Biorefining Ashton (4782) | POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005703 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00570300 | 28.39 | 5/6/2019 | None | Ethanol - Cellulosic | POET Biorefining Ashton (4782) | POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A005801 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A00580100 | 81.17 | 5/7/2019 | None | Ethanol | POET Biorefining Bingham Lake (4780) | POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005802 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A00580200 | 71.82 | 5/7/2019 | None | Ethanol | POET Biorefining Bingham Lake (4780) | POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005803 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00580300 | 31.75 | 5/7/2019 | None | Ethanol - Cellulosic | POET Biorefining Bingham Lake (4780) | POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC307 | 79.20 | ETH009A00620100 | 75.24 | 5/7/2019 | None | Ethanol | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC307 | 79.20 | ETH009A00620200 | 67.72 | 5/7/2019 | None | Ethanol | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETHCF207 | 35.67 | ETH012A00620300 | 27.36 | 5/7/2019 | None | Ethanol - Cellulosic | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006301 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Groton (4793); Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC308 | 78.56 | ETH009A00630100 | 75.15 | 5/7/2019 | None | Ethanol | POET Biorefining Groton (4793) | POET Biorefining Groton (70013) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006302 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC308 | 78.56 | ETH009A00630200 | 67.60 | 5/7/2019 | None | Ethanol | POET Biorefining Groton (4793) | POET Biorefining Groton (70013) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006303 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETHCF208 | 34.79 | ETH012A00630300 | 27.48 | 5/7/2019 | None | Ethanol - Cellulosic | POET Biorefining Groton (4793) | POET Biorefining Groton (70013) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006401 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC309 | 78.06 | ETH009A00640100 | 75.04 | 5/7/2019 | Legacy CI is from a composite pathway containing both dry and wet DGS. | Ethanol | POET Biorefining Gowrie (4784) | POET Biorefining Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006402 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC309 | 78.06 | ETH009A00640200 | 68.04 | 5/7/2019 | Legacy CI is from a composite pathway containing both dry and wet DGS. | Ethanol | POET Biorefining Gowrie (4784) | POET Biorefining Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006403 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETHCF209 | 34.30 | ETH012A00640300 | 27.72 | 5/7/2019 | None | Ethanol - Cellulosic | POET Biorefining Gowrie (4784) | POET Biorefining Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A007401 | Tier 1 | 3.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | California | Corn (009) | Ethanol (ETH) | ETHC216 | 69.64 | ETH009A00740100 | 65.77 | 3/29/2019 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | None | Retired |
| A007402 | Tier 1 | 3.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | California | Corn (009) | Ethanol (ETH) | ETHC217 | 65.36 | ETH009A00740200 | 61.54 | 3/29/2019 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | None | Retired |
| A007403 | Tier 1 | 3.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | California | Corn Fiber (012) | Ethanol (ETH) | ETHCF202 | 39.45 | ETH012A00740300 | 32.62 | 3/29/2019 | None | Ethanol - Cellulosic | Pacific Ethanol West (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional) | None | Retired |
| A008801 | Tier 1 | 3.0 | Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California | Colorado | Corn (009) | Ethanol (ETH) | ETHC228 | 67.68 | ETH009A00880100 | 64.61 | 5/17/2019 | None | Ethanol | Yuma Ethanol, LLC (4735) | Yuma Ethanol, LLC (70024) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California | None | Retired |
| A008901 | Tier 1 | 3.0 | Fuel Producer: Sterling Ethanol, LLC (4766) ; Facility Name: Sterling Ethanol, LLC (70660); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California | Colorado | Corn (009) | Ethanol (ETH) | ETHC283 | 69.39 | ETH009A00890100 | 64.10 | 5/17/2019 | None | Ethanol | Sterling Ethanol, LLC (4766) | Sterling Ethanol, LLC (70660) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California | None | Retired |
| A009901 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC303 | 78.68 | ETH009A00990100 | 73.79 | 5/17/2019 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional) | None | Retired |
| A009902 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC302 | 66.74 | ETH009A00990200 | 63.23 | 5/17/2019 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional) | None | Retired |
| A009401 | Tier 1 | 3.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) ; Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen) and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional) | California | Corn (009) | Ethanol (ETH) | ETHC211 | 70.23 | ETH009A00940100 | 67.03 | 5/21/2019 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen)and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional) | None | Retired |
| A005501 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A00550100 | 77.80 | 5/24/2019 | None | Ethanol | POET Biorefining Glenville (4779) | POET BIOREFINING GLENVILLE (AGRA RESOURC (70020) | Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005502 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A00550200 | 69.57 | 5/24/2019 | None | Ethanol | POET Biorefining Glenville (4779) | POET BIOREFINING GLENVILLE (AGRA RESOURC (70020) | Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005503 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00550300 | 29.51 | 5/24/2019 | None | Ethanol - Cellulosic | POET Biorefining Glenville (4779) | POET BIOREFINING GLENVILLE (AGRA RESOURC (70020) | Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A007801 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional) | Louisiana | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A00780100 | 61.21 | 5/29/2019 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Shreveport Biogas (70121) | Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A007802 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional) | Louisiana | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A00780200 | 64.29 | 5/29/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Shreveport Biogas (70121) | Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional) | None | Retired |
| A009801 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC225 | 67.10 | ETH009A00980100 | 61.48 | 5/29/2019 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California | None | Retired |
| A007201 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Louisiana | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A00720100 | 40.37 | 5/29/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Shreveport Biogas (70121) | Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| A011001 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01100100 | 46.54 | 5/29/2019 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Ameresco Woodland Meadows Romulus, LLC (A0833) | Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | None | Retired |
| A011002 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | Michigan | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A01100200 | 63.69 | 5/29/2019 | None | Bio-LNG | U.S. Venture, Inc. (5504) | Ameresco Woodland Meadows Romulus, LLC (A0833) | Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | None | Retired |
| A011003 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | Michigan | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A01100300 | 66.78 | 5/29/2019 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Ameresco Woodland Meadows Romulus, LLC (A0833) | Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional) | None | Retired |
| A008101 | Tier 1 | 3.0 | Fuel Producer: East Kansas Agri-Energy, LLC (4483) ; Facility Name: East Kansas Agri-Energy, LLC (83483); Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California | Kansas | Corn (009) | Ethanol (ETH) | None | None | ETH009A00810100 | 67.53 | 5/30/2019 | None | Ethanol | East Kansas Agri-Energy, LLC (4483) | East Kansas Agri-Energy, LLC (83483) | Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California | None | Retired |
| A005001 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | Missouri | Corn (009) | Ethanol (ETH) | None | None | ETH009A00500100 | 70.67 | 6/3/2019 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | None | Retired |
| A005002 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | Missouri | Corn (009) | Ethanol (ETH) | None | None | ETH009A00500200 | 62.76 | 6/3/2019 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | None | Retired |
| A005003 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | Missouri | Corn (009) | Ethanol (ETH) | None | None | ETH012A00500300 | 23.18 | 6/3/2019 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional) | None | Retired |
| A009501 | Tier 1 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: CEFARI RNG OKC, LLC (F00022); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | Oklahoma | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A00950100 | 51.74 | 6/3/2019 | None | Bio-CNG | Clean Energy (5481) | CEFARI RNG OKC, LLC (F00022) | Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional) | None | Retired |
| A006101 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC305 | 80.94 | ETH009A00610100 | 76.85 | 6/5/2019 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006102 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETHC305 | 80.94 | ETH009A00610200 | 69.76 | 6/5/2019 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A006103 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETHCF205 | 36.92 | ETH012A00610300 | 29.51 | 6/5/2019 | None | Ethanol - Cellulosic | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A008303 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | Minnesota | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC211 | 33.52 | BIO003A00830300 | 24.55 | 6/7/2019 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A008304 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A00830400 | 17.72 | 6/7/2019 | | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A008305 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A00830500 | 11.99 | 6/7/2019 | | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A008306 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | Minnesota | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT215 | 36.29 | BIO002A00830600 | 28.89 | 6/7/2019 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A010002 | Tier 1 | 3.0 | Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC275 | 76.35 | ETH009A01000200 | 67.48 | 6/7/2019 | None | Ethanol | The Andersons, Inc (5872) | The Andersons Denison Ethanol (70135) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | None | Retired |
| A005401 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00540100 | 73.97 | 6/10/2019 | None | Ethanol | Poet Biorefining Corning (5046) | Poet Biorefining Corning (70143) | Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005402 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00540200 | 67.03 | 6/10/2019 | None | Ethanol | Poet Biorefining Corning (5046) | Poet Biorefining Corning (70143) | Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005403 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00540300 | 27.26 | 6/10/2019 | None | Ethanol - Cellulosic | Poet Biorefining Corning (5046) | Poet Biorefining Corning (70143) | Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005601 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00560100 | 74.83 | 6/10/2019 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005602 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A00560200 | 68.44 | 6/10/2019 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A005603 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A00560300 | 28.47 | 6/10/2019 | None | Ethanol - Cellulosic | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A006001 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC301 | 79.55 | ETH009A00600100 | 73.99 | 6/10/2019 | None | Ethanol | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006002 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC301 | 79.55 | ETH009A00600200 | 66.22 | 6/10/2019 | None | Ethanol | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A006003 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETHCF204 | 35.39 | ETH012A00600300 | 26.08 | 6/10/2019 | None | Ethanol - Cellulosic | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A010301 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC234L | 67.73 | ETH009A01030100 | 75.50 | 6/28/2019 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | None | Retired |
| A010305 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | None | None | ETH009A01030500 | 63.21 | 6/28/2019 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | None | Retired |
| A010306 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG003 | 73.39 | ETH010A01030600 | 77.77 | 6/28/2019 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | None | Retired |
| A010307 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A01030700 | 65.48 | 6/28/2019 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California | None | Retired |
| A010101 | Tier 1 | 3.0 | Fuel Producer: American Greenfuels, LLC (6341) ; Facility Name: AMERICAN GREENFUELS LLC (83357); New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional) | Connecticut | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01010100 | 21.04 | 8/5/2019 | None | Biodiesel | American Greenfuels, LLC (6341) | AMERICAN GREENFUELS LLC (83357) | New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional) | None | Retired |
| A011201 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC315 | 72.14 | ETH009A01120100 | 68.75 | 8/5/2019 | None | Ethanol | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional) | None | Retired |
| A011202 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETHCF200R | 44.19 | ETH012A01120200 | 30.06 | 8/5/2019 | None | Ethanol - Cellulosic | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A011203 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A01120300 | 65.90 | 8/5/2019 | None | Ethanol | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional) | None | Retired |
| A012101 | Tier 1 | 3.0 | Fuel Producer: Golden Grain Energy, LLC (4829) ; Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC212 | 77.43 | ETH009A01210100 | 73.76 | 8/5/2019 | None | Ethanol | Golden Grain Energy, LLC (4829) | Golden Grain Energy (70691) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A012102 | Tier 1 | 3.0 | Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC213 | 73.86 | ETH009A01210200 | 70.53 | 8/5/2019 | None | Ethanol | Golden Grain Energy, LLC (4829) | Golden Grain Energy (70691) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012103 | Tier 1 | 3.0 | Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01210300 | 29.09 | 8/5/2019 | None | Ethanol - Cellulosic | Golden Grain Energy, LLC (4829) | Golden Grain Energy (70691) | Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A011801 | Tier 1 | 3.0 | Fuel Producer: Pacific Ethanol West (3697); Facility Name: Pacific Ethanol Magic Valley LLC (70291); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California | Idaho | Corn (009) | Ethanol (ETH) | ETHC251L | 68.89 | ETH009A01180100 | 66.44 | 8/6/2019 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Magic Valley LLC (70291) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California | None | Retired |
| A012502 | Tier 1 | 3.0 | Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC286 | 75.94 | ETH009A01250200 | 68.41 | 8/6/2019 | None | Ethanol | Plymouth Energy LLC (5474) | Plymouth Energy LLC (70183) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California | None | Retired |
| A013701 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC208R | 76.65 | ETH009A01370100 | 72.86 | 8/5/2019 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | None | Retired |
| A013702 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC208R | 76.65 | ETH009A01370200 | 69.05 | 8/5/2019 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | None | Retired |
| A013703 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC208R | 76.65 | ETH009A01370300 | 65.76 | 8/5/2019 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | None | Retired |
| A014501 | Tier 1 | 3.0 | Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC240L | 74.00 | ETH009A01450100 | 69.60 | 8/6/2019 | None | Ethanol | Redfield Energy, LLC (4061) | Redfield Energy, LLC (70111) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California | None | Retired |
| A010201 | Tier 1 | 3.0 | Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | ETHC289 | 75.43 | ETH009A01020100 | 69.29 | 8/9/2019 | None | Ethanol | Guardian Energy, LLC (3383) | Guardian Energy, LLC (70289) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A010202 | Tier 1 | 3.0 | Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01020200 | 26.35 | 8/9/2019 | None | Ethanol - Cellulosic | Guardian Energy, LLC (3383) | Guardian Energy, LLC (70289) | Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A010901 | Tier 1 | 3.0 | Fuel Producer: SIMPLE FUELS BIODIESEL INC (3717) ; Facility Name: SIMPLE FUELS BIODIESEL (80207); U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01090100 | 14.73 | 9/24/2019 | None | Biodiesel | SIMPLE FUELS BIODIESEL INC (3717) | SIMPLE FUELS BIODIESEL (80207) | U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional) | None | Retired |
| A012001 | Tier 1 | 3.0 | Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC239L | 70.04 | ETH009A01200100 | 63.44 | 9/5/2019 | None | Ethanol | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A012002 | Tier 1 | 3.0 | Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETHCF201R | 42.17 | ETH012A01200200 | 45.82 | 9/5/2019 | None | Ethanol - Cellulosic | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012701 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01270100 | 28.33 | 9/24/2019 | None | Ethanol - Cellulosic | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012702 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A01270200 | 75.89 | 9/24/2019 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012703 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A01270300 | 67.79 | 9/24/2019 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012801 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A01280100 | 77.91 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012802 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A01280200 | 67.99 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012803 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01280300 | 28.29 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012901 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A01290100 | 74.62 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012902 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A01290200 | 67.54 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A012903 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01290300 | 27.44 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A013001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01300100 | 74.35 | 9/24/2019 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | None | Retired |
| A013002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01300200 | 67.34 | 9/24/2019 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A013003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01300300 | 27.54 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | None | Retired |
| A013601 | Tier 1 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Live Oak Landfill Gas Plant (70002); Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional) | Georgia | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01360100 | 44.64 | 9/25/2019 | None | Bio-CNG | Shell Energy North America (6154) | Live Oak Landfill Gas Plant (70002) | Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional) | None | Retired |
| A014101 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | Missouri | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC212 | 37.30 | BIO003A01410100 | 29.40 | 9/25/2019 | None | Biodiesel | High Plains Bioenergy (4846) | HPB - St. Joe Biodiesel LLC (80059) | Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | None | Retired |
| A014102 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | Missouri | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A01410200 | 34.21 | 9/25/2019 | None | Biodiesel | High Plains Bioenergy (4846) | HPB - St. Joe Biodiesel LLC (80059) | Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | None | Retired |
| A013901 | Tier 1 | 3.0 | Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC279 | 69.83 | ETH009A01390100 | 62.81 | 9/9/2019 | None | Ethanol | Midwest Renewable Energy (5214) | Midwest Renewable Energy (70160) | Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional) | None | Retired |
| A014001 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC297 | 69.11 | ETH009A01400100 | 63.69 | 9/9/2019 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A014002 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC296 | 78.63 | ETH009A01400200 | 72.42 | 9/9/2019 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A014003 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG219 | 76.92 | ETH010A01400300 | 66.76 | 9/9/2019 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A014004 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG218 | 86.22 | ETH010A01400400 | 75.50 | 9/9/2019 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A014601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | Michigan | Corn (009) | Ethanol (ETH) | None | None | ETH009A01460100 | 72.59 | 9/24/2019 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | None | Retired |
| A014602 | Tier 1 | 3.0 | Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | Michigan | Corn (009) | Ethanol (ETH) | None | None | ETH009A01460200 | 67.10 | 9/24/2019 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | None | Retired |
| A014603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | Michigan | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01460300 | 27.33 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A015501 | Tier 1 | 3.0 | Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC203 | 76.69 | ETH009A01550100 | 67.97 | 9/24/2019 | None | Ethanol | Absolute Energy, LLC (5049) | Absolute Energy, LLC (70144) | Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional) | None | Retired |
| A017001 | Tier 1 | 3.0 | Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC317 | 65.03 | ETH009A01700100 | 62.21 | 9/6/2019 | None | Ethanol | Pratt Energy, LLC (6127) | Pratt Energy, LLC (70158) | Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | None | Retired |
| A017002 | Tier 1 | 3.0 | Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC304 | 77.71 | ETH009A01700200 | 76.40 | 9/6/2019 | None | Ethanol | Pratt Energy, LLC (6127) | Pratt Energy, LLC (70158) | Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | None | Retired |
| A017003 | Tier 1 | 3.0 | Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A01700300 | 65.67 | 9/6/2019 | None | Ethanol | Pratt Energy, LLC (6127) | Pratt Energy, LLC (70158) | Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | None | Retired |
| A017004 | Tier 1 | 3.0 | Fuel Producer: Pratt Energy, LLC (6127); Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A01700400 | 79.86 | 9/6/2019 | None | Ethanol | Pratt Energy, LLC (6127) | Pratt Energy, LLC (70158) | Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California | None | Retired |
| A013101 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Soybean Oil (005) | Biodiesel (BIO) | BDS204 | 59.99 | BIO005A01310100 | 57.00 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013102 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A01310200 | 52.00 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013103 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC207 | 37.94 | BIO003A01310300 | 27.90 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013104 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU215 | 25.46 | BIO001A01310400 | 21.00 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013105 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130) ; Facility Name: REG Mason City, LLC (82968); U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU236 | 18.34 | BIO001A01310500 | 16.20 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013106 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | Iowa | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT208 | 39.70 | BIO002A01310600 | 32.50 | 10/8/2019 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | None | Retired |
| A013201 | Tier 1 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Northeast Mississippi Landfill Gas Recovery Project (71317); Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional) | Mississippi | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01320100 | 40.08 | 9/30/2019 | None | Bio-CNG | Clean Energy (5481) | Northeast Mississippi Landfill Gas Recovery Project (71317) | Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A015001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01500100 | 74.83 | 10/3/2019 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01500300 | 27.72 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015101 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01510100 | 74.44 | 10/3/2019 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional) | None | Retired |
| A015103 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01510300 | 27.69 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064 | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108 | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A01520100 | 74.15 | 10/3/2019 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | Ohio | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01520300 | 27.00 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A01520200 | 67.32 | 10/3/2019 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | None | Retired |
| A015102 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01510200 | 67.72 | 10/3/2019 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A016101 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | Texas | Corn (009) | Ethanol (ETH) | ETHC206 | 70.43 | ETH009A01610100 | 64.69 | 10/8/2019 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | None | Retired |
| A016103 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETHG202 | 77.05 | ETH010A01610300 | 66.62 | 10/8/2019 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | None | Retired |
| A016104 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | Texas | Corn (009) | Ethanol (ETH) | ETHC205 | 78.02 | ETH009A01610400 | 72.64 | 10/8/2019 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | None | Retired |
| A016105 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETHG201 | 84.64 | ETH010A01610500 | 74.57 | 10/8/2019 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A015002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A01500200 | 68.05 | 10/14/2019 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | None | Retired |
| A016401 | Tier 1 | 3.0 | Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | ETHC236L | 76.96 | ETH009A01640100 | 67.23 | 10/15/2019 | None | Ethanol | BUSHMILLS ETHANOL, INC. (4063) | BUSHMILLS ETHANOL, INC. (70109) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional) | None | Retired |
| A017501 | Tier 1 | 3.0 | Fuel Producer: Front Range Energy LLC (4758); Facility Name: Front Range Energy LLC (70058); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California | Colorado | Corn (009) | Ethanol (ETH) | ETH009A01220100 | 63.60 | ETH009A01750100 | 64.25 | 10/21/2019 | None | Ethanol | Front Range Energy LLC (4758) | Front Range Energy LLC (70058) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California | None | Retired |
| A015401 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional) | Kentucky | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01540100 | 54.66 | 11/5/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional) | None | Retired |
| A015402 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional) | Kentucky | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A01540200 | 71.50 | 11/5/2019 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional) | None | Retired |
| A015403 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional) | Kentucky | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A01540300 | 74.59 | 11/5/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional) | None | Retired |
| T2N-1019 | Tier 2 | 2.0 | Biomethane produced from the high-solids (greater than 15 percent total solids) anaerobic digestion of food and green wastes; compressed in CA | California | HSAD Food & Green Waste | Compressed Natural Gas | None | None | CNG005_1 | -22.93 | 9/25/2018 | None | Bio-CNG | Blue Line Transfer, Inc. (L500) | Blue Line Transfer, Inc. (B1725) | Biomethane produced from the highsolids (greater than 15 percent total solids)anaerobic digestion of food and green wastes; compressed in CA | None | Retired |
| None | Lookup Table | 2.0 | Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity. | NA | Waste Water | Compressed Natural Gas (CNG) | None | None | CNG020_1 | 7.75 | NA | None | Bio-CNG | NA | NA | Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity. | None | Retired |
| None | Lookup Table | 2.0 | Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling. | NA | Waste Water | Compressed Natural Gas (CNG) | None | None | CNG021_1 | 30.92 | NA | None | Bio-CNG | NA | NA | Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling. | None | Retired |
| None | Lookup Table | 2.0 | Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps) | NA | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYGN001_1 | 151.01 | NA | None | Hydrogen | NA | NA | Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps) | None | Retired |
| None | Lookup Table | 2.0 | Liquid H2 from central reforming of NG | NA | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYGN002_1 | 143.51 | NA | None | Hydrogen | NA | NA | Liquid H2 from central reforming of NG | None | Retired |
| None | Lookup Table | 2.0 | Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps) | NA | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYGN003_1 | 105.65 | NA | None | Hydrogen | NA | NA | Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| None | Lookup Table | 2.0 | Compressed H2 from on-site reforming of NG | NA | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYGN004_1 | 105.13 | NA | None | Hydrogen | NA | NA | Compressed H2 from on-site reforming of NG | None | Retired |
| None | Lookup Table | 2.0 | Compressed H2 from on-site reforming with renewable feedstocks | NA | Any Other Feedstock (998) | Gaseous Hydrogen (HYG) | None | None | HYGN005_1 | 88.33 | NA | None | Hydrogen | NA | NA | Compressed H2 from on-site reforming with renewable feedstocks | None | Retired |
| A016501 | Tier 1 | 3.0 | Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional) | Rhode Island | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01650100 | 15.24 | 12/16/2019 | None | Biodiesel | NEWPORT BIODIESEL INC (7764) | NEWPORT BIODIESEL LLC (83532) | Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional) | None | Retired |
| A016502 | Tier 1 | 3.0 | Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional) | Rhode Island | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01650200 | 18.60 | 12/16/2019 | None | Biodiesel | NEWPORT BIODIESEL INC (7764) | NEWPORT BIODIESEL LLC (83532) | Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional) | None | Retired |
| A016301 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California | Texas | Corn (009) | Ethanol (ETH) | ETHC200 | 70.79 | ETH009A01630100 | 64.74 | 12/16/2019 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California | None | Retired |
| A016302 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETHG200 | 79.03 | ETH010A01630200 | 66.63 | 12/16/2019 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California | None | Retired |
| T1N-1753 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ | Ohio | Landfill Gas | LNG | LNGLF225 | 56.57 | LNGLF225R | 65.22 | 12/18/2019 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | WM Renewable Energy of Ohio - American Landfill (71222) | American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ | None | Retired |
| T1N-1785 | Tier 1 | 2.0 | Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power. | Iowa | Corn | Ethanol | ETHC292 | 73.11 | ETHC292R | 74.42 | 12/18/2019 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power. | None | Retired |
| T2N-1229 | Tier 2 | 2.0 | Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California | Oregon | Used Cooking Oil (UCO) | Biodiesel | BDU241 | 18.43 | BDU241R | 18.71 | 12/18/2019 | Application Package | Biodiesel | SeQuential Pacific Biodiesel LLC (6129) | SeQuential-Pacific Biodiesel, LLC. (83525) | Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California | None | Retired |
| T1N-1809 | Tier 1 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | Pennsylvania | Landfill Gas | CNG | CNGLF273 | 49.77 | CNGLF273R | 52.94 | 12/18/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Shade (71134) | JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | None | Retired |
| A010501 | Tier 1 | 3.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker | South Korea | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01050100 | 27.89 | 12/17/2019 | None | Biodiesel | Dansuk Industrial Co., Ltd (5953) | Pyeongtaek 2 (80202) | South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker | None | Retired |
| A017601 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311) ; Facility Name: Meadow Branch (A2316); Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01760100 | 49.24 | 12/18/2019 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Meadow Branch (A2316) | Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | None | Retired |
| A011501 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | Texas | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNGWW201 | 43.02 | CNG030A01150100 | 37.33 | 12/19/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ameresco San Antonio Biogas (71204) | Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | None | Retired |
| A016001 | Tier 1 | 3.0 | Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01600100 | 44.90 | 12/20/2019 | None | Bio-CNG | Iogen D3 Biofuel Partners LLC (6486) | GSF Energy-Rumpke Landfill (71138S) | Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B005402 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) ; Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RDU202R1 | 19.73 | RND001B00540200 | 19.92 | 12/19/2019 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | None | Retired |
| B005401 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | Louisiana | Distillers' Corn Oil (003) | Renewable Diesel (RND) | RDC201 | 31.27 | RND003B00540100 | 27.42 | 12/19/2019 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | None | Retired |
| B005403 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RDT204R1 | 30.79 | RND002B00540300 | 31.86 | 12/19/2019 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional) | None | Retired |
| A013501 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional) | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT202 | 35.57 | BIO002A01350100 | 32.07 | 12/20/2019 | None | Biodiesel | High Plains Bioenergy (4846) | High Plains Bioenergy (82883) | Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional) | None | Retired |
| B003101 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B00310100 | 131.39 | 12/31/2019 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations | None | Retired |
| B004501 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B00450100 | 25.08 | 12/27/2019 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | None | Retired |
| B004502 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B00450200 | 25.08 | 12/27/2019 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B004503 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B00450300 | 25.08 | 12/27/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B004401 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B00440100 | 42.91 | 12/27/2019 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | None | Retired |
| B004301 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B00430100 | 37.13 | 12/27/2019 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | None | Retired |
| B004302 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RDT209 | 38.75 | RND002B00430200 | 37.13 | 12/27/2019 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B004303 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNWN200 | 39.75 | RNT002B00430300 | 37.13 | 12/27/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B004402 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B00440200 | 42.91 | 12/27/2019 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B004403 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B00440300 | 42.91 | 12/27/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B004601 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491) ; Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B00460100 | 158.15 | 12/31/2019 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Praxair Liquid H2 Source (F00053) | Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA | None | Retired |
| B004602 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B00460200 | 136.31 | 12/31/2019 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Praxair Liquid H2 Source (F00053) | Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA | None | Retired |
| B004701 | Tier 2 | 3.0 | Fuel Producer: Sinclair Wyoming Refining Company (3994); Facility Name: Sinclair Wyoming Refining Company (83388); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional) | Wyoming | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B00470100 | 58.34 | 12/27/2019 | Application Package | Renewable Diesel | Sinclair Wyoming Refining Company (3994) | Sinclair Wyoming Refining Company (83388) | Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional) | None | Retired |
| B004901 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B00490100 | 158.28 | 12/31/2019 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Air Products Sacramento Liquid Sacramento (F00103) | Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California | None | Retired |
| B004902 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B00490200 | 136.44 | 12/31/2019 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Air Products Sacramento Liquid Sacramento (F00103) | Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California | None | Retired |
| A019501 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A01950100 | 43.37 | 12/31/2019 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060) | Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | None | Retired |
| T2R-1105 | Tier 2 | 2.0 | Fuel Producer: Tracy Renewable Energy LLC (T534) Facility Name: Tracy Renewable Energy LLC (A0640): Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and co-products (compost and animal feed). | California | Sugarbeets | Ethanol | ETHBE001 | 13.64 | ETHB200L | 7.18 | 5/16/2016 | None | Ethanol | Tracy Renewable Energy LLC (T534) | Tracy Renewable Energy LLC (A0640) | Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and coproducts (compost and animal feed) | None | Retired |
| T2R-1073 | Tier 2 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California, Dry Mill, Waste Wine Ethanol, NG | California | Waste Wine | Ethanol | ETHWB002 | 18.70 | ETHWB200L | 22.06 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | California, Dry Mill, Waste Wine Ethanol, NG | None | Retired |
| T1R-1518 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC125 | 67.92 | ETHC271L | 56.44 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | None | Retired |
| T1R-1248 | Tier 1 | 2.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC120 | 62.76 | ETHC257L | 56.82 | 3/31/2016 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1195 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, California Ethanol, Dry Mill, WDGS, North American LFG | California | Corn | Ethanol | ETHC117 | 65.07 | ETHC249L | 58.11 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | California Corn, California Ethanol, Dry Mill, WDGS, North American LFG | None | Retired |
| T1R-1250 | Tier 1 | 2.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG | California | Corn | Ethanol | ETHC122 | 69.78 | ETHC259L | 58.31 | 3/31/2016 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG | None | Retired |
| T1R-1199 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG | California | Corn | Ethanol | ETHC119 | 70.56 | ETHC250L | 59.04 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG | None | Retired |
| T1R-1515 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC128 | 68.20 | ETHC268L | 60.27 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | None | Retired |
| T1R-1517 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC124 | 68.43 | ETHC270L | 61.94 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer | None | Retired |
| T1R-1513 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC127 | 75.34 | ETHC267L | 63.23 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | None | Retired |
| T1R-1520 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | California | Sorghum | Ethanol | ETHG023 | 69.19 | ETHG211L | 64.34 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer | None | Retired |
| T1R-1519 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC126 | 75.77 | ETHC272L | 64.89 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer | None | Retired |
| T1N-1231 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, Ethanol, Dry Mill, NG | California | Corn | Ethanol | None | None | ETHC217 | 65.36 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | California Corn, Ethanol, Dry Mill, NG | None | Retired |
| T1R-1251 | Tier 1 | 2.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer | California | Sorghum | Ethanol | ETHG020 | 68.24 | ETHG208L | 66.07 | 3/31/2016 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer | None | Retired |
| T1N-1358 | Tier 1 | 2.0 | Fuel Producer: Bridgeport Ethanol, LLC (5934) Facility Name: Bridgeport Ethanol, LLC (70217). Midwest Corn, Ethanol, Dry Mill, WDGS, NG | Nebraska | Corn | Ethanol | None | None | ETHC229 | 67.43 | 3/31/2016 | None | Ethanol | Bridgeport Ethanol, LLC (5934) | Bridgeport Ethanol, LLC (70217) | Midwest Corn, Ethanol, Dry Mill, WDGS, NG | None | Retired |
| T1R-1249 | Tier 1 | 2.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer | California | Corn | Ethanol | ETHC121 | 72.42 | ETHC258L | 67.46 | 3/31/2016 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| None | Lookup Table | 3.0 | California grid electricity used as a transportation fuel in California | California | Grid Electricity (039) | Electricity (ELC) | None | None | ELC000L00072019 | 81.49 | NA | None | Electricity | NA | NA | California grid electricity used as a transportation fuel in California | None | Retired |
| T1R-1197 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG | California | Sorghum | Ethanol | ETHG018 | 68.19 | ETHG206L | 68.62 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG | None | Retired |
| T1N-1230 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, Ethanol, Dry Mill, NG | California | Corn | Ethanol | None | None | ETHC216 | 69.64 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest Corn, Ethanol, Dry Mill, NG | None | Retired |
| T1N-1609 | Tier 1 | 2.0 | Fuel Producer: Great Plains Ethanol (4727) Facility Name: Great Plains Ethanol, LLC (70012): Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas | South Dakota | Corn | Ethanol | None | None | ETHC280 | 69.68 | 1/10/2017 | None | Ethanol | Great Plains Ethanol (4727) | Great Plains Ethanol, LLC (70012) | Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas | None | Retired |
| T1N-1152 | Tier 1 | 2.0 | Fuel Producer: Trenton Agri Products, LLC (4754) Facility Name: Trenton Agri Products, LLC (70053). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | None | None | ETHC210 | 69.75 | 3/31/2016 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1N-1592 | Tier 1 | 2.0 | Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG | Kansas | Corn | Ethanol | None | None | ETHC278 | 70.60 | 11/2/2016 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG | None | Retired |
| T1N-1070 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | Texas | Corn | Ethanol | None | None | ETHC200 | 70.79 | 3/31/2016 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | None | Retired |
| T1R-1514 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | California | Sorghum | Ethanol | ETHG025 | 76.91 | ETHG210L | 70.80 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer | None | Retired |
| T1N-1500 | Tier 1 | 2.0 | Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: POET Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | South Dakota | Corn | Ethanol | None | None | ETHC231 | 71.14 | 3/31/2016 | None | Ethanol | POET Biorefining Mitchell (4789) | POET Biorefining Mitchell (70016) | Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG | None | Retired |
| T1R-1013 T1R-1052 | Tier 1 | 2.0 | Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) Facility Name: Mid America Agri Products/Wheatland LLC (70153). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC110 ETHC111 | 82.76 76.68 | ETHC235L | 71.78 | 3/31/2016 | None | Ethanol | Mid America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1003 | Tier 1 | 2.0 | Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Corn Ethanol, Dry Mill, NG | Kansas | Corn | Ethanol | ETHC037 | 80.17 | ETHC233L | 71.79 | 3/31/2016 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1015 | Tier 1 | 2.0 | Fuel Producer: BUSHMILLS ETHANOL, INC. (4063) Facility Name: BUSHMILLS ETHANOL, INC. (70109). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG | Minnesota | Corn | Ethanol | ETHC113 | 79.18 | ETHC232L | 72.55 | 3/31/2016 | None | Ethanol | BUSHMILLS ETHANOL, Inc (4063) | BUSHMILLS ETHANOL, Inc (70109) | Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1521 | Tier 1 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer | California | Sorghum | Ethanol | ETHG024 | 77.04 | ETHG212L | 72.59 | 3/31/2016 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer | None | Retired |
| T1N-1539 | Tier 1 | 2.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels | Nebraska | Corn | Ethanol | None | None | ETHC276 | 72.63 | 11/2/2016 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels | None | Retired |
| T1N-1132 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG | California | Corn | Ethanol | ETHC207 | 72.73 | ETHC207R | 72.94 | 5/16/2018 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Madera LLC (70061) | Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG | None | Retired |
| T1N-1082 | Tier 1 | 2.0 | Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG **(Provisional)** | Iowa | Corn | Ethanol | None | None | ETHC202 | 73.55 | 3/31/2016 | None | Ethanol | Little Sioux Corn Processors, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG (Provisional) | None | Retired |
| T1N-1176 | Tier 1 | 2.0 | Fuel Producer: High Plains Bioenergy (4846) Facility Name: High Plains Bioenergy (82883). Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE) | Guymon, Oklahoma | Mixture of Tallow and Choice White Grease | Biodiesel | None | None | BDT202 | 35.57 | 6/30/2016 | None | Biodiesel | High Plains Bioenergy (4846) | High Plains Bioenergy (82883) | Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE) | None | Retired |
| T1R-1294 | Tier 1 | 2.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG | Nebraska | Corn | Ethanol | ETHC047 | 83.74 | ETHC266L | 73.78 | 3/31/2016 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG | None | Retired |
| T1R-1292 | Tier 1 | 2.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG | Nebraska | Corn | Ethanol | ETHC046 | 84.41 | ETHC265L | 74.05 | 3/31/2016 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG | None | Retired |
| T1R-1291 | Tier 1 | 2.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG | Nebraska | Corn | Ethanol | ETHC045 | 85.16 | ETHC264L | 74.37 | 3/31/2016 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG | None | Retired |
| T1R-1216 | Tier 1 | 2.0 | Fuel Producer: Husker Ag LLC (5078) Facility Name: Husker Ag LLC (70151). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC092 | 81.92 | ETHC253L | 74.56 | 3/31/2016 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1032 | Tier 1 | 2.0 | Fuel Producer: E Energy Adams, LLC (4831) Facility Name: E energy Adams, LLC (70093). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC067_1 | 86.31 | ETHC238L | 74.62 | 3/31/2016 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |
| T1R-1006 | Tier 1 | 2.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054) Facility Name: Bonanza BioEnergy, LLC (70117). Midwest, Sorghum Ethanol, Dry Mill, NG | Kansas | Sorghum | Ethanol | ETHG003 | 73.39 | ETHG205L | 74.83 | 3/31/2016 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest, Sorghum Ethanol, Dry Mill, NG | None | Retired |
| T1R-1286 | Tier 1 | 2.0 | Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, NG | Nebraska | Corn | Ethanol | ETHC043 | 88.14 | ETHC263L | 75.27 | 3/31/2016 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest, Corn Ethanol, Dry Mill, NG | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1198 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG | California | Sorghum | Ethanol | ETHG019 | 79.97 | ETHG207L | 76.14 | 3/31/2016 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Stockton LLC (70319) | Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG | None | Retired |
| T1R-1252 | Tier 1 | 2.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer | California | Sorghum | Ethanol | ETHG021 | 79.60 | ETHG209L | 76.33 | 3/31/2016 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer | None | Retired |
| T1N-1217 | Tier 1 | 2.0 | Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG | Kansas | Corn | Ethanol | None | None | ETHC214 | 76.66 | 3/31/2016 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG | None | Retired |
| T1N-1081 | Tier 1 | 2.0 | Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG **(Provisional)** | Iowa | Corn | Ethanol | None | None | ETHC201 | 77.66 | 3/31/2016 | None | Ethanol | Little Sioux Corn Processors, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG (Provisional) | None | Retired |
| T1N-1222 | Tier 1 | 2.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792) Facility Name: Poet Biorefining Emmetsburg (70021). Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG | Iowa | Corn | Ethanol | None | None | ETHC215 | 77.98 | 3/31/2016 | None | Ethanol | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG | None | Retired |
| T1N-1593 | Tier 1 | 2.0 | Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG | Kansas | Sorghum | Ethanol | None | None | ETHG215 | 78.55 | 11/2/2016 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG | None | Retired |
| T1N-1072 | Tier 1 | 2.0 | Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG | Texas | Sorghum | Ethanol | None | None | ETHG200 | 79.03 | 3/31/2016 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG | None | Retired |
| T1R-1004 | Tier 1 | 2.0 | Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Sorghum Ethanol, Dry Mill, NG | Kansas | Sorghum | Ethanol | ETHG004 | 76.22 | ETHG204L | 79.28 | 3/31/2016 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest, Sorghum Ethanol, Dry Mill, NG | None | Retired |
| T1N-1133 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG | California | Sorghum | Ethanol | ETHG203 | 80.51 | ETHG203R | 81.84 | 5/16/2018 | None | Ethanol | Pacific Ethanol West (3697) | Pacific Ethanol Madera LLC (70061) | Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG | None | Retired |
| T1N-1499 | Tier 1 | 2.0 | Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: Poet Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | South Dakota | Corn | Ethanol | None | None | ETHC230 | 81.74 | 3/31/2016 | None | Ethanol | POET Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG | None | Retired |
| T1N-1151 | Tier 1 | 2.0 | Fuel Producer: Cornhusker Energy Lexington, LLC (7365) Facility Name: Lexington Ethanol Plant (70241). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG | Nebraska | Corn | Ethanol | None | None | ETHC209 | 85.58 | 3/31/2016 | None | Ethanol | Cornhusker Energy Lexington, LLC (7365) | Lexington Ethanol Plant (70241) | Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG | None | Retired |
| T2N-1137 | Tier 2 | 2.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Soybean, Fuel produced in Louisiana and transported to California | Louisiana | Soybean | Renewable Diesel | None | None | RDS200 | 53.86 | 3/21/2017 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from US Soybean, Fuel produced in Louisiana and transported to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1138 | Tier 2 | 2.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California | Louisiana | Used Cooking Oil | Renewable Diesel | None | None | RDU202 | 20.28 | 3/21/2017 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California | None | Retired |
| T2N-1144 | Tier 2 | 2.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Corn Oil, Fuel produced in Louisiana and transported to California | Louisiana | Corn Oil | Renewable Diesel | None | None | RDC201 | 31.27 | 3/21/2017 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from US Corn Oil, Fuel produced in Louisiana and transported to California | None | Retired |
| T2R-1204 | Tier 2 | 2.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California | Louisiana | Used Cooking Oil | Renewable Diesel | RDU202 | 20.28 | RDU202R1 | 19.73 | 6/23/2017 | None | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California | None | Retired |
| T2R-1205 | Tier 2 | 2.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Tallow, Fuel produced in Louisiana and transported to California | Louisiana | Tallow | Renewable Diesel | RDT204 | 30 | RDT204R1 | 30.79 | 6/23/2017 | None | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Renewable Diesel produced from US Tallow, Fuel produced in Louisiana and transported to California | None | Retired |
| T1N-1572 | Tier 1 | 2.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power. | Nebraska | Corn | Ethanol | None | None | ETHC293 | 68.89 | 12/21/2017 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Dry mill corn ethanol with coproduction of MDGS and corn oil using natural gas and electricity power | None | Retired |
| T2N-1210 | Tier 2 | 2.0 | Fuel Producer: Siouxland Energy Cooperative (4060) Facility Name: Siouxland Energy Cooperative (70112):Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional) | Iowa | Corn Kernel Fiber | Ethanol | ETHCF201 | 29.93 | ETHCF201R | 42.17 | 11/29/2018 | Pathway Details (PDF) | Ethanol - Cellulosic | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1156 | Tier 2 | 2.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Tier 2 Method 2B Pathway: Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using grid-based electricity, and delivered to CNG dispensing stations in California via pipeline | Texas | Waste Water | CNG | None | None | CNGWW201 | 43.02 | 3/16/2018 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ameresco San Antonio Biogas (71204) | Tier 2 Method 2B Pathway Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using gridbased electricity, and delivered to CNG dispensing stations in California via pipeline | None | Retired |
| T1N-1814 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline to WM fueling stations in California (Provisional) | Illinois | Landfill Gas | CNG | None | None | CNGLF270 | 62.72 | 6/1/2018 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline to WM fueling stations in California (Provisional) | None | Retired |
| T1N-1815 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas pipeline-quality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional) | Illinois | Landfill Gas | LNG | None | None | LNGLF228 | 76.13 | 6/1/2018 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | Waste Management's Milam landfill, St Louis, Illinois gas pipelinequality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional) | None | Retired |
| T1N-1816 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified and compressed in California. (Provisional) | Illinois | Landfill Gas | CNG | None | None | CNGLF271 | 78.68 | 6/1/2018 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified and compressed in California(Provisional) | None | Retired |
| T1N-1828 | Tier 1 | 2.0 | Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional) | Nebraska | Corn | Ethanol | None | None | ETHC295 | 74.03 | 7/9/2018 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional) | None | Retired |
| T1N-1859 | Tier 1 | 2.0 | Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products (Provisional) | Kansas | Corn | Ethanol | None | None | ETHC299 | 67.83 | 8/27/2018 | None | Ethanol | Kansas Ethanol, LLC (5810) | Kansas Ethanol, LLC (70279) | Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuelsDDGS, WDGS, and corn oil as coproducts (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1235 | Tier 2 | 2.0 | Fuel Producer: Pacific Ethanol West LLC (3697); Facility Name: Pacific Ethanol Stockton LLC (70319; Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional) | California | Corn Kernel Fiber | Ethanol | None | None | ETHCF202 | 39.45 | 9/28/2018 | Application Package | Ethanol - Cellulosic | Pacific Ethanol West LLC (3697) | Pacific Ethanol Stockton LLC (70319) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional) | None | Retired |
| T2N-1252 | Tier 2 | 2.0 | Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Kernel Fiber | Ethanol | None | None | ETHCF203 | 27.69 | 9/28/2018 | Application Package | Ethanol - Cellulosic | Great Plains Ethanol (4727) | Great Plains Ethanol, LLC (70012) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1266 | Tier 2 | 2.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792) ; Facility Name: Poet Biorefining Emmetsburg (70021); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional) | Iowa | Corn Kernel Fiber | Ethanol | None | None | ETHCF204 | 35.39 | 9/28/2018 | Application Package | Ethanol - Cellulosic | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1153 | Tier 2 | 2.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California | Iowa | Corn Kernel Fiber | Ethanol | ETHCF200 | 31.23 | ETHCF200R | 44.19 | 11/29/2018 | Application Package | Ethanol - Cellulosic | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California | None | Retired |
| T2N-1258 | Tier 2 | 2.0 | Fuel Producer: POET Biorefining - Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Kernel Fiber | Ethanol | None | None | ETHCF205 | 36.92 | 12/4/2018 | Application Package | Ethanol - Cellulosic | POET Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1262 | Tier 2 | 2.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | Iowa | Corn Kernel Fiber | Ethanol | None | None | ETHCF209 | 34.30 | 12/4/2018 | Application Package | Ethanol - Cellulosic | POET Biorefining Gowrie (4784) | POET Biorefining Gowrie (70033) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1261 | Tier 2 | 2.0 | Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Kernel Fiber | Ethanol | None | None | ETHCF208 | 34.79 | 12/4/2018 | Application Package | Ethanol - Cellulosic | POET Biorefining Groton (4793) | POET Biorefining Groton (70013) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1260 | Tier 2 | 2.0 | Fuel Producer: POET Biorefining - Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Kernel Fiber | Ethanol | None | None | ETHCF207 | 35.67 | 12/4/2018 | Application Package | Ethanol - Cellulosic | POET Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1263 | Tier 2 | 2.0 | Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) ; Facility Name: Mid America Agri Products/Wheatland LLC (70153); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional) | Nebraska | Corn | Ethanol | None | None | ETHC311 | 38.12 | 12/18/2018 | Application Package | Ethanol | Mid America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional) | None | Retired |
| T1N-1870 | Tier 1 | 2.0 | Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional) | Arizona | Corn | Ethanol | None | None | ETHC314 | 74.77 | 12/21/2018 | None | Ethanol | Pinal Energy LLC (4744) | Pinal Energy LLC (70136) | Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional) | None | Retired |
| T2N-1279 | Tier 2 | 2.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354); Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Tier 2 Method 2B Pathway: Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional) | California | Corn | Ethanol | None | None | ETHC316 | 63.01 | 12/31/2018 | Application Package | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Tier 2 Method 2B Pathway Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional) | None | Retired |
| T2N-1290 | Tier 2 | 2.0 | Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California (Provisional) | California | Tallow & Animal Fat | Renewable Diesel | None | None | RDT209 | 38.75 | 1/16/2019 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Tier 2 Method 2B ApplicationRenewable Diesel produced from North American Tallow, in Paramount, California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T2N-1287 | Tier 2 | 2.0 | Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional) | California | Tallow & Animal Fat | Renewable Naphtha | None | None | RNWN200 | 39.75 | 3/14/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Tier 2 Method 2B ApplicationRenewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional) | None | Retired |
| T1N-1805 | Tier 1 | 2.0 | Fuel Producer: Pacific Ethanol Holding Co LLC (3697); Facility Name: Pacific Ethanol Madera LLC (70061); Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power | California | Corn | Ethanol | ETHC290 | 69.81 | ETHC290R | 69.94 | 12/18/2019 | None | Ethanol | Pacific Ethanol Holding Co LLC (3697) | Pacific Ethanol Madera LLC (70061) | Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power | None | Retired |
| T1N-1870 | Tier 1 | 2.0 | Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California | Arizona | Corn | Ethanol | ETHC314 | 74.77 | ETHC314R | 75.62 | 12/18/2019 | None | Ethanol | Pinal Energy LLC (4744) | Pinal Energy LLC (70136) | Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California | None | Retired |
| T1N-1869 | Tier 1 | 2.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | Nebraska | Corn | Ethanol | ETHC302 | 66.74 | ETHC302R | 68.86 | 12/18/2019 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | None | Retired |
| T1N-1868 | Tier 1 | 2.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | Nebraska | Corn | Ethanol | ETHC303 | 78.68 | ETHC303R | 79.25 | 12/18/2019 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | None | Retired |
| T1N-1874 | Tier 1 | 2.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727) ; Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California | South Dakota | Corn | Ethanol | ETHC300 | 69.04 | ETHC300R | 69.07 | 12/18/2019 | None | Ethanol | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California | None | Retired |
| T1N-1895 | Tier 1 | 2.0 | Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California | Nebraska | Corn | Ethanol | ETHC310 | 70.76 | ETHC310R | 71.08 | 12/18/2019 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California | None | Retired |
| B003201 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B00320100 | 158.25 | 1/13/2020 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | LAX Station (L0324) | Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles | None | Retired |
| B003202 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031B00320200 | 176.43 | 1/13/2020 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | LAX Station (L0324) | Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles | None | Retired |
| T1N-1785 | Tier 1 | 2.0 | Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power | Iowa | Corn | Ethanol | ETHC292R | 74.42 | ETHC292R1 | 74.18 | 1/16/2020 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power | None | Retired |
| T1N-1869 | Tier 1 | 2.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | Nebraska | Corn | Ethanol | ETHC302R | 68.86 | ETHC302R1 | 66.94 | 1/16/2020 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | None | Retired |
| T1N-1868 | Tier 1 | 2.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | Nebraska | Corn | Ethanol | ETHC303R | 79.25 | ETHC303R1 | 79.21 | 1/16/2020 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC (70098) | Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B001801 | Tier 2 | 3.0 | Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional) | Washington | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B00180100 | 26.92 | 12/6/2019 | Application Package | Renewable Diesel | BP Products North America, Inc (4320) | Cherry Point Refinery (83736) | U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional) | None | Retired |
| B003601 | Tier 2 | 3.0 | Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Facility Name: Praxair Ontario (F00084); Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional) | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B00360100 | 76.71 | 1/21/2020 | Application Package | Hydrogen | HIGH MOUNTAIN FUELS LLC (4293) | Facility Name: Praxair Ontario (F00084) | Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional) | None | Retired |
| B003602 | Tier 2 | 3.0 | Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Praxair Ontario (F00084); Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional) | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B00360200 | 96.41 | 1/21/2020 | Application Package | Hydrogen | HIGH MOUNTAIN FUELS LLC (4293) | Praxair Ontario (F00084) | Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional) | None | Retired |
| B004801 | Tier 2 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B00480100 | 138.90 | 1/29/2020 | Application Package | Hydrogen | Shell Energy North America (6154) | Sacramento Hydrogen Plant (F00102) | Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA | None | Retired |
| B000901 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B00090100 | -323.83 | 1/31/2020 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Locust Ridge Farm (71298) | Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | None | Retired |
| B000902 | Tier 2 | 3.0 | Fuel Producer: Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional) | Missouri | Swine Manure (044) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN044B00090200 | -308.93 | 1/31/2020 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Locust Ridge Farm (71298) | Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional) | None | Retired |
| B000903 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | Missouri | Swine Manure (044) | Liquefied Natural Gas (LNG) | None | None | LNG044B00090300 | -312.47 | 12/31/2019 | Application Package | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Locust Ridge Farm (71298) | Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | None | Retired |
| B001001 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B00100100 | -345.68 | 1/31/2020 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | None | Retired |
| B001002 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | Missouri | Swine Manure (044) | Liquefied Natural Gas (LNG) | None | None | LNG044B00100200 | -334.41 | 1/31/2020 | Application Package | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional) | None | Retired |
| B001003 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional) | Missouri | Swine Manure (044) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN044B00100300 | -330.87 | 1/31/2020 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional) | None | Retired |
| None | Lookup Table | 3.0 | California grid electricity used as a transportation fuel in California | California | Grid Electricity (039) | Electricity (ELC) | None | None | ELC000L00072020 | 82.92 | NA | None | Electricity | NA | NA | California grid electricity used as a transportation fuel in California | None | Retired |
| T1R-1119 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to LNG then to L-CNG | California | Landfill Gas | CNG | CNGLF211LR | 44.05 | CNGLF211LR1 | 44.07 | 3/30/2020 | None | Bio-CNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec LFG to LNG then to L-CNG | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1R-1120 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to CNG for California CNG stations | California | Landfill Gas | CNG | CNGLF212L | 31.96 | CNGLF212LR | 31.98 | 3/30/2020 | None | Bio-CNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec LFG to CNG for California CNG stations | None | Retired |
| T1R-1121 | Tier 1 | 2.0 | Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to LNG facility in Boron for use in California | California | Landfill Gas | LNG | LNGLF207LR | 41.44 | LNGLF207LR1 | 41.46 | 3/30/2020 | None | Bio-LNG | Clean Energy (5481) | Complexe Enviro Progressive Itee (71198) | Quebec LFG to LNG facility in Boron for use in California | None | Retired |
| T2N-1154 | Tier 2 | 2.0 | Fuel Producer: Biodico Westside (6231); Facility Name: Biodico Plant (83027); California Used Cooking Oil, Biodiesel produced in Five Points, California. | California | Used Cooking Oil (UCO) | Biodiesel | BDU229 | 14.97 | BDU229R | 25.91 | 4/2/2020 | Application Package | Biodiesel | Biodico Westside (6231) | Biodico Plant (83027) | California Used Cooking Oil, Biodiesel produced in Five Points, California. | None | Retired |
| T1N-1572 | Tier 1 | 2.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power. | Nebraska | Corn | Ethanol | ETHC293 | 68.89 | ETHC293R | 69.02 | 4/2/2020 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power. | None | Retired |
| T1N-1811 | Tier 1 | 2.0 | Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | California | Landfill Gas | CNG | CNGLF277 | 32.28 | CNGLF277R | 37.39 | 4/2/2020 | None | Bio-CNG | San Diego Metropolitan Transit Center (S304) | EBI Energie In (71254) | EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | None | Retired |
| T1N-1859 | Tier 1 | 2.0 | Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products | Kansas | Corn | Ethanol | ETHC299 | 67.83 | ETHC299R | 68.72 | 4/2/2020 | None | Ethanol | Kansas Ethanol, LLC | Kansas Ethanol, LLC (70279) | Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products | None | Retired |
| T2N-1287 | Tier 2 | 2.0 | Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow,  Naphtha produced in Paramount, California | California | Tallow & Animal Fat | Renewable Naphtha | RNWN200 | 39.75 | RNWN200R | 43.14 | 4/2/2020 | Application Package | Renewable Gasoline | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow,  Naphtha produced in Paramount, California | None | Retired |
| T2N-1290 | Tier 2 | 2.0 | Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California | California | Tallow & Animal Fat | Renewable Diesel | RDT209 | 38.75 | RDT209R | 39.91 | 4/2/2020 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California | None | Retired |
| A021201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO;  Ethanol transported by rail to California (Provisional) | Missouri | Corn (009) | Ethanol (ETH) | None | None | ETH009A02120100 | 75.09 | 4/28/2020 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO;  Ethanol transported by rail to California (Provisional) | None | Retired |
| A021202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (Provisional) | Missouri | Corn (009) | Ethanol (ETH) | None | None | ETH009A02120200 | 65.67 | 4/28/2020 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ;  Ethanol transported by rail to California (Provisional) | None | Retired |
| A021203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO;  Ethanol transported by rail to California (Provisional) | Missouri | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A02120300 | 26.19 | 4/28/2020 | None | Ethanol - Cellulosic | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill;  Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional) | None | Retired |
| T1N-1384 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California | Bakersfield, California | North American Used Cooking Oil | Biodiesel | BDU203 | 18.18 | BDU203R | 18.31 | 6/9/2020 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average North American Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| T1N-1386 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Tallow to Biodiesel Produced in California | Bakersfield, California | North American Tallow | Biodiesel | BDT203 | 30.60 | BDT203R | 31.39 | 6/9/2020 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average US Sourced Tallow to Biodiesel Produced in California | None | Retired |
| T1N-1389 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Tallow to Biodiesel Produced in California | Bakersfield, California | California Tallow | Biodiesel | BDT204 | 28.45 | BDT204R | 28.92 | 6/9/2020 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average California Sourced Tallow to Biodiesel Produced in California | None | Retired |
| T2N-1107 | Tier 2 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California | Bakersfield, California | Used Cooking Oil | Biodiesel | BDU204 | 13.93 | BDU204R | 14.70 | 6/9/2020 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California | None | Retired |
| T1N-1800 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Enegy LP (4814) ; Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Average California sourced Used Cooking Oil UCO) to Biodiesel produced in California | California | Used Cooking Oil | Biodiesel | BDU233 | 18.16 | BDU233R | 18.22 | 6/9/2020 | None | Biodiesel | Crimson Renewable Enegy LP (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | Average California sourced Used Cooking Oil (UCO) to Biodiesel produced in California | None | Retired |
| A022801 | Tier 1 | 3.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional) | Arizona | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02280100 | 77.65 | 6/16/2020 | None | Bio-LNG | Applied Natural Gas Fuels, Inc. (6174) | Apex LFG Energy (F00034) | Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional) | None | Retired |
| A022802 | Tier 1 | 3.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional) | Arizona | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02280200 | 80.74 | 6/16/2020 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | Apex LFG Energy (F00034) | Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional) | None | Retired |
| A022701 | Tier 1 | 3.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional) | Arizona | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02270100 | 63.13 | 6/16/2020 | None | Bio-LNG | Applied Natural Gas Fuels, Inc. (6174) | Timberline Energy, LLC (F00028) | Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional) | None | Retired |
| A022702 | Tier 1 | 3.0 | Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) ; Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional) | Arizona | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02270200 | 66.21 | 6/16/2020 | None | Bio-CNG | Applied Natural Gas Fuels, Inc. (6174) | Timberline Energy, LLC (F00028) | Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in California (Provisional) | None | Retired |
| A021802 | Tier 1 | 3.0 | Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Washington | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02180200 | 50.02 | 6/22/2020 | None | Bio-LNG | PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080) | H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301) | Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A021803 | Tier 1 | 3.0 | Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional) | Washington | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02180300 | 53.11 | 6/22/2020 | None | Bio-CNG | PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080) | H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301) | Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional) | None | Retired |
| A021901 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc, pipelined to California for compression to CNG (Provisional) | Canada | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02190100 | 38.64 | 6/22/2020 | None | Bio-CNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG (Provisional) | None | Retired |
| A021902 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stationso California by pipeline, liquefied in California (Provisional) | Canada | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02190200 | 51.69 | 6/22/2020 | None | Bio-LNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A021903 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional) | Canada | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02190300 | 54.77 | 6/22/2020 | None | Bio-CNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional) | None | Retired |
| A021301 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00070100 | 65.21 | ETH009A02130100 | 61.55 | 6/22/2020 | None | Ethanol | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional) | None | Retired |
| A021302 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00070200 | 25.06 | ETH012A02130200 | 21.31 | 6/22/2020 | None | Ethanol - Cellulosic | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A019801 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00980100 | 61.48 | ETH009A01980100 | 61.26 | 6/24/2020 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional) | None | Retired |
| A019802 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A01980200 | 23.46 | 6/24/2020 | None | Ethanol - Cellulosic | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional) | None | Retired |
| A020901 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A01370100 | 72.86 | ETH009A02090100 | 73.74 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A020902 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A01370200 | 69.05 | ETH009A02090200 | 70.47 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A020903 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A01370300 | 65.76 | ETH009A02090300 | 66.86 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A020904 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A02090400 | 27.48 | 6/24/2020 | None | Ethanol - Cellulosic | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional) | None | Retired |
| A022401 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01120100 | 68.75 | ETH009A02240100 | 69.32 | 6/24/2020 | None | Ethanol | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A022402 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01120300 | 65.90 | ETH009A02240200 | 66.23 | 6/24/2020 | None | Ethanol | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A022403 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A02240300 | 63.27 | 6/24/2020 | None | Ethanol | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A022404 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A01120200 | 30.06 | ETH012A02240400 | 23.96 | 6/24/2020 | None | Ethanol - Cellulosic | LSCP, LLLP (4728) | LSCP, LLLP (70015) | Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A020001 | Tier 1 | 3.0 | Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF264 | 43.97 | CNG025A02000100 | 40.13 | 6/29/2020 | None | Bio-CNG | GHI Energy, LLC (6156) | Waste Management American Landfill (70421) | Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional) | None | Retired |
| B010001 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B01000100 | 23.93 | 6/29/2020 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional) | None | Retired |
| B010002 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01000200 | 23.93 | 6/29/2020 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional) | None | Retired |
| B010003 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01000300 | 23.93 | 6/29/2020 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Rendered Animal Fat Oil from Greely, Colorado transported by train to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional) | None | Retired |
| B005901 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00590100 | -558.62 | 6/30/2020 | Application Package | Electricity | California Bioenergy LLC (B194) | ABEC Bidart-Old River LLC (F00113) | Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | None | Retired |
| B008901 | Tier 2 | 3.0 | Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00890100 | -108.43 | 6/30/2020 | Application Package | Electricity | Gallo Cattle Company, LP (C1029) | Cottonwood Dairy (F00094) | Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional) | None | Retired |
| B009801 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980100 | -355.35 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional) | None | Retired |
| B009802 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980200 | -377.83 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | None | Retired |
| B009805 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980500 | -368.04 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | None | Retired |
| B009806 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980600 | -374.10 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | None | Retired |
| A021701 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | North Dakota | Corn (009) | Ethanol (ETH) | ETHC287 | 75.23 | ETH009A02170100 | 69.84 | 7/27/2020 | None | Ethanol | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A021702 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | North Dakota | Corn (009) | Ethanol (ETH) | ETHC287 | 75.23 | ETH009A02170200 | 66.96 | 7/27/2020 | None | Ethanol | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A021703 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | North Dakota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A02170300 | 25.72 | 7/27/2020 | None | Ethanol - Cellulosic | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A023201 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02320100 | 43.15 | 7/24/2020 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Renovar Arlington, LTD RNG Project (70501) | Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional) | None | Retired |
| A023301 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional) | Kansas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02330100 | 45.91 | 7/24/2020 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional) | None | Retired |
| A023805 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | Canada | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A02380500 | 36.98 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | None | Retired |
| A023808 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | Canada | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A02380800 | 22.81 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | None | Retired |
| A024901 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A02490100 | 74.54 | 7/24/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional) | None | Retired |
| A024902 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A02490200 | 67.28 | 7/24/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional) | None | Retired |
| T1R-1184 | Tier 1 | 2.0 | Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | Brazil | Sugarcane (018) | Ethanol | ETHS204L | 38.98 | ETHS204LR | 41.52 | 8/13/2020 | None | Ethanol | BP Biofuels (4427) | Ituiutaba Bioenergia Ltda (71006) | Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | None | Retired |
| T1R-1185 | Tier 1 | 2.0 | Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | Brazil | Molasses (019) | Ethanol | ETHM204L | 38.30 | ETHM204LR | 40.84 | 8/13/2020 | None | Ethanol | BP Biofuels (4427) | Ituiutaba Bioenergia Ltda (71006) | Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | None | Retired |
| T1R-1183 | Tier 1 | 2.0 | Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | Brazil | Molasses (019) | Ethanol | ETHM203L | 39.84 | ETHM203LR | 42.42 | 8/13/2020 | None | Ethanol | BP Biofuels (4427) | Central Itumbiara de Bioenergia e Alimentos Ltda (71007) | Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting | None | Retired |
| T1R-1182 | Tier 1 | 2.0 | Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | Brazil | Sugarcane (018) | Ethanol | ETHS203L | 40.74 | ETHS203LR | 43.32 | 8/13/2020 | None | Ethanol | BP Biofuels (4427) | Central Itumbiara de Bioenergia e Alimentos Ltda (71007) | Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B005801 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00580100 | -167.04 | 12/31/2019 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B005802 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00580200 | -151.41 | 12/31/2019 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional) | None | Retired |
| B005803 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00580300 | -257.78 | 12/31/2019 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B006001 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00600100 | -255.74 | 2/24/2020 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Fair Oaks Upgrader, LLC (71001) | Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional) | None | Retired |
| T1N-1387 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional) | Bakersfield, California | CA Corn Oil from Wet DGS | Biodiesel | None | None | BDC202 | 27.45 | 6/30/2016 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional) | None | Retired |
| T1N-1388 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California **(Provisional)** | Bakersfield, California | U.S. Corn Oil from Wet DGS | Biodiesel | None | None | BDC203 | 28.48 | 6/30/2016 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average US Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional) | None | Retired |
| T1N-1543 | Tier 1 | 2.0 | Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average Global Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California **(Provisional)** | Bakersfield, California | Global Used Cooking Oil | Biodiesel | None | None | BDU205 | 23.28 | 6/30/2016 | None | Biodiesel | Crimson Renewable Energy LP (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Average Global Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California (Provisional) | None | Retired |
| T1N-1670 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ | Pennsylvania | Landfill Gas | Liquefied Natural Gas | LNGLF226 | 66.92 | LNGLF226R | 70.36 | 9/22/2020 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Valley LFG, LLC (71137) | Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ | None | Retired |
| T1N-1671 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA. | Pennsylvania | Landfill Gas | Compressed Natural Gas | CNGLF266 | 69.47 | CNGLF266R | 72.91 | 9/22/2020 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Valley LFG, LLC (71137) | Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA. | None | Retired |
| T1N-1669 | Tier 1 | 2.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations | Pennsylvania | Landfill Gas | Compressed Natural Gas | CNGLF267 | 54.61 | CNGLF267R | 57.83 | 9/22/2020 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Valley LFG, LLC (71137) | Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations | None | Retired |
| A027101 | Tier 1 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454) ; Facility Name: Jaxon Energy, LLC (83608); Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional) | Mississippi | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003A02710100 | 78.60 | 10/2/2020 | None | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional) | None | Retired |
| A026501 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A02650100 | 73.16 | 10/9/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | HUB CITY ENERGY LLC (70721) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024701 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02470100 | 49.78 | 10/13/2020 | None | Bio-CNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG | None | Retired |
| B007201 | Tier 2 | 3.0 | Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional) | Oregon | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00720100 | -188.78 | 9/30/2020 | Application Package | Bio-CNG | IOGEN D3 BIOFUEL PARTNERS II LLC (7180) | WOF PNW Threemile Project (F00100) | Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B007901 | Tier 2 | 3.0 | Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B00790100 | 30.48 | 9/30/2020 | Application Package | Renewable Diesel | Kern Oil & Refining Co. (5038) | Kern Oil & Refining Co. (80105) | Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional) | None | Retired |
| B007902 | Tier 2 | 3.0 | Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B00790200 | 41.85 | 9/30/2020 | Application Package | Renewable Diesel | Kern Oil & Refining Co. (5038) | Kern Oil & Refining Co. (80105) | Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional) | None | Retired |
| B010901 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01090100 | -453.10 | 9/30/2020 | Application Package | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B010902 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01090200 | -308.48 | 9/30/2020 | Application Package | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B010903 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01090300 | -236.96 | 9/30/2020 | Application Package | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B009601 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00960100 | -532.74 | 9/30/2020 | Application Package | Bio-CNG | Clean Energy (5481) | Calumet - Dairy Dreams (F00127) | Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B009701 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00970100 | -372.20 | 9/30/2020 | Application Package | Bio-CNG | Clean Energy (5481) | Calumet - Ponderosa (F00128) | Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B010801 | Tier 2 | 3.0 | Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional) | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01080100 | -230.13 | 9/30/2020 | Application Package | Bio-CNG | AgPower Jerome, LLC (C1036) | AgPower Jerome RNG Project (F00077) | Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| A024201 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF250 | 54.87 | CNG025A02420100 | 47.53 | 10/29/2020 | None | Bio-CNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG | None | Retired |
| A024202 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations | Tennessee | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02420200 | 60.15 | 10/29/2020 | None | Bio-LNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024203 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | Tennessee | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02420300 | 63.24 | 10/29/2020 | None | Bio-CNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | None | Retired |
| A027201 | Tier 1 | 3.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETHC295 | 74.03 | ETH009A02720100 | 65.63 | 10/21/2020 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional) | None | Retired |
| A027202 | Tier 1 | 3.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A02720200 | 26.60 | 10/21/2020 | None | Ethanol - Cellulosic | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional) | None | Retired |
| A025901 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Distillers' Corn Oil (003) | Biodiesel (BIO) | None | None | BIO003A02590100 | 36.62 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | None | Retired |
| A025902 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A02590200 | 66.13 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | None | Retired |
| A025903 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A02590300 | 41.88 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | None | Retired |
| A024101 | Tier 1 | 3.0 | Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional) | Canada | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02410100 | 29.92 | 11/12/2020 | None | Bio-CNG | COMPLEXE ENVIRO CONNEXIONS LTEE (6282) | Complexe Enviro Connexions (F00139) | Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A024102 | Tier 1 | 3.0 | Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional) | Canada | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02410200 | 42.70 | 11/12/2020 | None | Bio-LNG | COMPLEXE ENVIRO CONNEXIONS LTEE (6282) | Complexe Enviro Connexions (F00139) | Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional) | None | Retired |
| A024103 | Tier 1 | 3.0 | Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional) | Canada | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02410300 | 45.78 | 11/12/2020 | None | Bio-CNG | COMPLEXE ENVIRO CONNEXIONS LTEE (6282) | Complexe Enviro Connexions (F00139) | Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A024801 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products | Iowa | Corn (009) | Ethanol (ETH) | ETHC220 | 78.14 | ETH009A02480100 | 70.62 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Fort Dodge (70043) | Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products | None | Retired |
| A024802 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC220 | 78.14 | ETH009A02480200 | 67.47 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Fort Dodge (70043) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California | None | Retired |
| A025601 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC262L | 76.74 | ETH009A02560100 | 71.32 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Aurora, South Dakota (70041) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A025602 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETHC262L | 76.74 | ETH009A02560200 | 68.05 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Aurora, South Dakota (70041) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California | None | Retired |
| A025401 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI | Iowa | Corn (009) | Ethanol (ETH) | ETHC260L | 78.62 | ETH009A02540100 | 69.55 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Albert City (70142) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI | None | Retired |
| A025402 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC260L | 78.62 | ETH009A02540200 | 66.07 | 11/18/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Albert City (70142) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California | None | Retired |
| A024301 | Tier 1 | 3.0 | Fuel Producer: LES RENEWABLE NG LLC (6223); Facility Name: LES RENEWABLE NG LLC (71157); Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02430100 | 60.40 | 11/19/2020 | None | Bio-CNG | LES RENEWABLE NG LLC (6223) | LES RENEWABLE NG LLC (71157) | Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG | None | Retired |
| A028201 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional) | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT202 | 35.57 | BIO002A02820100 | 27.02 | 11/20/2020 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional) | None | Retired |
| B011401 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B01140100 | 109.68 | 11/25/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California | None | Retired |
| B011501 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426) ; Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California. | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B01150100 | 73.14 | 11/25/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products and Chemicals SMR Wilmington. CA (F00068) | Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California. | None | Retired |
| B012801 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B01280100 | 153.91 | 11/25/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California | None | Retired |
| B010201 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020100 | -408.6 | CNG026B01020101 | -408.62 | 12/3/2020 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B010202 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01020200 | -289.76 | 12/3/2020 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B010203 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01020300 | -308.74 | 12/3/2020 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| A024501 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00570100 | 76.25 | ETH009A02450100 | 69.92 | 12/4/2020 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024502 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00570200 | 67.07 | ETH009A02450200 | 62.54 | 12/4/2020 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A024503 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00570300 | 28.39 | ETH012A02450300 | 22.56 | 12/4/2020 | None | Ethanol - Cellulosic | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A025501 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC106 | 86.49 | ETH009A02550100 | 71.02 | 12/3/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Albion (702830) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California | None | Retired |
| A025502 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC107 | 82.37 | ETH009A02550200 | 67.05 | 12/3/2020 | None | Ethanol | Valero Renewable Fuels (3201) | Albion (702830) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California | None | Retired |
| A029701 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Kansas | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02970101 | 58.34 | 12/15/2020 | None | Bio-LNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A029702 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Kansas | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02970200 | 61.43 | 12/15/2020 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| B011901 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B01190100 | 19.51 | 12/18/2020 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | None | Retired |
| B011902 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01190200 | 19.51 | 12/18/2020 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional) | None | Retired |
| B011903 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01190300 | 19.51 | 12/18/2020 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional) | None | Retired |
| B008002 | Tier 2 | 3.0 | Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional) | California | Other Organic Waste (029) | Electricity (ELC) | None | None | ELC029B00800200 | -233.49 | 12/31/2020 | Application Package | Electricity | Bridge To Renewables, Benefit LLC (C1006) | Blake's Landing Farms (F00019) | Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional) | None | Retired |
| B009901 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Corn (009) | Ethanol (ETH) | ETHC282 | 80.85 | ETH009B00990101 | 74.02 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |
| B009902 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Corn (009) | Ethanol (ETH) | ETHC281 | 72.32 | ETH009B00990200 | 63.64 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B009903 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG217 | 88.90 | ETH010B00990300 | 77.27 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |
| B009904 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG216 | 80.38 | ETH010B00990400 | 66.90 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |
| B009905 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Wheat Starch Slurry (014) | Ethanol (ETH) | ETHWSS201 | 53.73 | ETH014B00990500 | 52.76 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |
| B009906 | Tier 2 | 3.0 | Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail | Kansas | Wheat Starch Slurry (014) | Ethanol (ETH) | ETHWSS200 | 45.2 | ETH014B00990600 | 47.78 | 12/31/2020 | Application Package | Ethanol | PureField Ingredients LLC (7241) | PureField Ingredients LLC (70302) | Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail | None | Retired |
| A024601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A02460100 | 77.21 | 12/29/2020 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | None | Retired |
| A024602 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | None | None | ETH009A02460200 | 69.47 | 12/29/2020 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | None | Retired |
| A024603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A02460300 | 29.41 | 12/29/2020 | None | Ethanol - Cellulosic | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional) | None | Retired |
| B012701 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01270100 | -417.35 | 12/31/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B012702 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007) ; Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01270200 | -417.27 | 12/31/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B012703 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01270300 | -418.90 | 12/31/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B012704 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01270400 | -392.44 | 12/31/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B014501 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B01450100 | -287.07 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products and Chemicals SMR Wilmington. CA (F00068) | Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B014502 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B01450200 | -216.05 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products and Chemicals SMR Wilmington. CA (F00068) | Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California | None | Retired |
| B014601 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B01460100 | 120.04 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California | None | Retired |
| B014602 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B01460200 | 164.27 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California | None | Retired |
| B016401 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B01640100 | -251.36 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California | None | Retired |
| B016402 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B01640200 | -241.00 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California | None | Retired |
| B016403 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B01640300 | -179.71 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California | None | Retired |
| B016404 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B01640400 | -169.35 | 12/31/2020 | Application Package | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California | None | Retired |
| B010201 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020100 | -408.60 | CNG026B01020101 | -408.62 | 12/3/2020 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| A027401 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional) | Texas | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A02740100 | 38.37 | 3/1/2021 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Renovar Arlington, LTD RNG Project (70501) | Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional) | None | Retired |
| A033001 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00990100 | 73.79 | ETH009A03300100 | 73.75 | 3/1/2021 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A027901 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | Arkansas | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC210 | 38.75 | BIO003A02790100 | 33.97 | 3/9/2021 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | None | Retired |
| A027902 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | Arkansas | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU207L | 24.36 | BIO001A02790200 | 27.05 | 3/9/2021 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029801 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional) | Washington | Landfill Gas (025) | Compressed Natural Gas (CNG) | LNGLF206LR | 40.21 | CNG025A02980100 | 28.24 | 3/12/2021 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A029802 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Washington | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNGLF206LR | 40.21 | LNG025A02980200 | 41.09 | 3/12/2021 | None | Bio-LNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A029803 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Washington | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | CNGLF229LR | 42.78 | LCN025A02980300 | 44.18 | 3/12/2021 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A026703 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02670300 | 55.90 | 3/18/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Raeger (71131) | Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A026702 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02670200 | 52.82 | 3/18/2021 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Raeger (71131) | Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A026701 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF275 | 42.86 | CNG025A02670100 | 35.51 | 3/18/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Raeger (71131) | Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A026203 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF273R | 49.77 | CNG025A02620300 | 52.21 | 3/18/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Shade (71134) | Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A026202 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02620200 | 72.80 | 3/18/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Shade (71134) | Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A026201 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02620100 | 69.71 | 3/18/2021 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Shade (71134) | Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A026401 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02640100 | 77.89 | 3/17/2021 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Southern Alleghenies (71133) | Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A026402 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02640200 | 80.98 | 3/17/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Southern Alleghenies (71133) | Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A026403 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF274 | 58.84 | CNG025A02640300 | 60.28 | 3/17/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Johnstown Regional Energy - Southern Alleghenies (71133) | Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029401 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETH009A01400200 | 72.42 | ETH009A02940100 | 70.88 | 3/22/2021 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A029402 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETH009A01400100 | 63.69 | ETH009A02940200 | 61.90 | 3/22/2021 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A029403 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A01400400 | 75.50 | ETH010A02940300 | 74.04 | 3/22/2021 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California | None | Retired |
| A029404 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A01400300 | 66.76 | ETH010A02940400 | 65.06 | 3/22/2021 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. | None | Retired |
| A031002 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Louisiana | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A03100200 | 53.73 | 3/18/2021 | None | Bio-LNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A031003 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Louisiana | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A03100300 | 56.81 | 3/18/2021 | None | Bio-CNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A031201 | Tier 1 | 3.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | California | Soybean Oil (005) | Biodiesel (BIO) | BDS201 | 52.45 | BIO005A03120100 | 57.16 | 3/23/2021 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | None | Retired |
| A031202 | Tier 1 | 3.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | California | Canola Oil (006) | Biodiesel (BIO) | BDCA201 | 54.97 | BIO006A03120200 | 51.65 | 3/23/2021 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | None | Retired |
| A031204 | Tier 1 | 3.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT205 | 32.24 | BIO002A03120400 | 31.28 | 3/23/2021 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. | None | Retired |
| A031205 | Tier 1 | 3.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT206 | 28.90 | BIO002A03120500 | 32.45 | 3/23/2021 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | None | Retired |
| A031206 | Tier 1 | 3.0 | Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A03120600 | 21.27 | 3/23/2021 | None | Biodiesel | American Biodiesel, Inc., dba Community Fuels (4935) | Community Fuels Port of Stockton (82728) | US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | None | Retired |
| B005901 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00590100 | -558.62 | ELC026B00590101 | -562.50 | 3/25/2021 | Application Package | Electricity | California Bioenergy LLC (B194) | ABEC Bidart-Old River LLC (F00113) | Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B008901 | Tier 2 | 3.0 | Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00890100 | -108.43 | ELC026B00890101 | -126.52 | 3/25/2021 | Application Package | Electricity | Gallo Cattle Company, LP (C1029) | Cottonwood Dairy (F00094) | Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional) | None | Retired |
| B013311 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01331100 | 26.5 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013312 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01331200 | 28.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| A029501 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU219 | 21.73 | BIO001A02950100 | 21.93 | 4/1/2021 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | None | Retired |
| A029502 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU240 | 19 | BIO001A02950200 | 16.98 | 4/1/2021 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | None | Retired |
| A030601 | Tier 1 | 3.0 | Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A03060100 | 41.93 | 4/6/2021 | None | Bio-CNG | MONROEVILLE LFG, LLC (6317) | MONROEVILLE LFG, LLC (71136) | Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional) | None | Retired |
| B018908 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01890800 | 27.00 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018909 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01890900 | 28.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018917 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891700 | 27.00 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018918 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891800 | 28.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| None | Lookup Table | 3.0 | California grid electricity used as a transportation fuel in California | California | Grid Electricity (039) | Electricity (ELC) | None | None | ELC000L00072021 | 75.93 | NA | None | Electricity | NA | NA | California grid electricity used as a transportation fuel in California | None | Retired |
| A028807 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | Iowa | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A02880700 | 24.50 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A030901 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03090100 | 24.46 | 5/4/2021 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A030902 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | ETHC247L | 75.15 | ETH009A03090200 | 71.95 | 5/4/2021 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A036702 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional) | Tennessee | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A03670200 | 62.18 | 5/11/2021 | None | Bio-LNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A036703 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional) | Tennessee | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A03670300 | 65.26 | 5/11/2021 | None | Bio-CNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A028501 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU204R | 14.7 | BIO001A02850100 | 12.91 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | None | Retired |
| A028502 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A02850200 | 12.93 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | None | Retired |
| A028503 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU203R | 18.31 | BIO001A02850300 | 17.86 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | None | Retired |
| A028504 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A02850400 | 15.81 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | None | Retired |
| A028505 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck. | California | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC202 and BDC203 | 27.45 and 28.48 | BIO003A02850500 | 25.22 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck. | None | Retired |
| A028506 | Tier 1 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT203R | 31.39 | BIO002A02850600 | 30.94 | 6/2/2021 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174) | US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A035101 | Tier 1 | 3.0 | Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00370100 | 66.53 | ETH009A03510100 | 65.93 | 6/1/2021 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional) | None | Retired |
| A029002 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | Illinois | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A02900200 | 57.00 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | None | Retired |
| A029003 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | Illinois | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A02900300 | 53.00 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | None | Retired |
| A029006 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU246 | 23.18 | BIO001A02900600 | 20.25 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | None | Retired |
| A034701 | Tier 1 | 3.0 | Fuel Producer: SENECA ENERGY II, LLC (6222); Facility Name: SENECA ENERGY (71156); Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional) | New York | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF207L | 52.77 | CNG025A03470100 | 44.49 | 6/10/2021 | None | Bio-CNG | SENECA ENERGY II, LLC (6222) | SENECA ENERGY (71156) | Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional) | None | Retired |
| A030401 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional) | California | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A03040100 | 30.31 | 6/14/2021 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Point Loma Digester Gas Project (F00027) | Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional) | None | Retired |
| A034601 | Tier 1 | 3.0 | Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF206L | 41.61 | CNG025A03460100 | 63.75 | 6/16/2021 | None | Bio-CNG | PINNACLE GAS PRODUCERS, LLC (6220) | PINNACLE GAS PRODUCERS, LLC (71153) | Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG | None | Retired |
| A034602 | Tier 1 | 3.0 | Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations | Ohio | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNGLF201LR | 50.27 | LNG025A03460200 | 76.91 | 6/16/2021 | None | Bio-LNG | PINNACLE GAS PRODUCERS, LLC (6220) | PINNACLE GAS PRODUCERS, LLC (71153) | Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations | None | Retired |
| A034603 | Tier 1 | 3.0 | Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | Ohio | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | CNGLF224LR | 56.01 | LCN025A03460300 | 80.00 | 6/16/2021 | None | Bio-CNG | PINNACLE GAS PRODUCERS, LLC (6220) | PINNACLE GAS PRODUCERS, LLC (71153) | Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | None | Retired |
| A034501 | Tier 1 | 3.0 | Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF237L | 47.40 | CNG025A03450100 | 52.66 | 6/16/2021 | None | Bio-CNG | WESTSIDE GAS PRODUCERS, LLC (6218) | WESTSIDE GAS PRODUCERS, LLC (71151) | Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. | None | Retired |
| B016301 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01630100 | -758.46 | 6/21/2021 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Hilarides (F00006) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B019001 | Tier 2 | 3.0 | Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | Kansas | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B01900100 | 46.31 | 6/25/2021 | Application Package | Renewable Diesel | East Kansas Agri-Energy, LLC (4483) | East Kansas Agri-Energy, LLC (83483) | Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | None | Retired |
| B019002 | Tier 2 | 3.0 | Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | Kansas | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | None | None | RNT003B01900200 | 46.31 | 6/25/2021 | Application Package | Renewable Naphtha | East Kansas Agri-Energy, LLC (4483) | East Kansas Agri-Energy, LLC (83483) | Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | None | Retired |
| B019301 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional) | North Dakota | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B01930100 | 34.90 | 6/25/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional) | None | Retired |
| B019302 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional) | North Dakota | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B01930200 | 64.24 | 6/25/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional) | None | Retired |
| B019303 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional) | North Dakota | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | None | None | RNT003B01930300 | 34.90 | 6/25/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional) | None | Retired |
| B019304 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional) | North Dakota | Soybean Oil (005) | Renewable Naphtha (RNT) | None | None | RNT005B01930400 | 64.24 | 6/25/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional) | None | Retired |
| B014301 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B00100100 | -345.68 | CNG044B01430100 | -429.05 | 6/29/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations | None | Retired |
| B014901 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B01490100 | -359.66 | 6/29/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | South Meadows Farm (F00195) | Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional) | None | Retired |
| B016801 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B01680100 | 33.42 | 6/29/2021 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | None | Retired |
| B016802 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01680200 | 33.42 | 6/29/2021 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional) | None | Retired |
| B016803 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01680300 | 33.42 | 6/29/2021 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional) | None | Retired |
| B019101 | Tier 2 | 3.0 | Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional) | California | Urban Landscaping Waste (028) | Compressed Natural Gas (CNG) | None | None | CNG028B01910100 | 2.51 | 6/29/2021 | Application Package | Bio-CNG | California Renewable Power LLC(C196) | California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270) | Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A037601 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional) | California | Distillers' Corn Oil (003) | Biodiesel (BIO) | None | None | BIO003A03760100 | 32.12 | 6/30/2021 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL (80341) | U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional) | None | Retired |
| A036601 | Tier 1 | 3.0 | Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional) | Georgia | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A03660100 | 61.39 | 7/7/2021 | None | Biodiesel | World Energy Rome, LLC (4533) | World Energy Rome, LLC (82470) | Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional) | None | Retired |
| A036602 | Tier 1 | 3.0 | Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional) | Georgia | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A03660200 | 24.94 | 7/7/2021 | None | Biodiesel | World Energy Rome, LLC (4533) | World Energy Rome, LLC (82470) | US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional) | None | Retired |
| A036603 | Tier 1 | 3.0 | Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional) | Georgia | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A03660300 | 36.60 | 7/7/2021 | None | Biodiesel | World Energy Rome, LLC (4533) | World Energy Rome, LLC (82470) | US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional) | None | Retired |
| A038601 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02560100 | 71.32 | ETH009A03860100 | 72.20 | 7/13/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A038602 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02560200 | 68.05 | ETH009A03860200 | 69.20 | 7/13/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A034801 | Tier 1 | 3.0 | Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional) | Texas | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT217 | 38.27 | BIO002A03480100 | 30.80 | 7/28/2021 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional) | None | Retired |
| A037501 | Tier 1 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A03750100 | 37.82 | 8/20/2021 | None | Bio-CNG | BLUE SOURCE LLC (6086) | Seabreeze Energy Producers (70281) | Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional) | None | Retired |
| B017301 | Tier 2 | 3.0 | Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional) | Idaho | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01730100 | -545.71 | 9/22/2021 | Application Package | Electricity | DF-AP #1, LLC (C1122) | Big Sky Dairy Digester (F00329) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional) | None | Retired |
| B017401 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | South Dakota | Corn (009) | Ethanol (ETH) | ETHC306 | 81.86 | ETH009B01740100 | 75.91 | 9/24/2021 | Application Package | Ethanol | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | None | Retired |
| B017402 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | South Dakota | Corn (009) | Ethanol (ETH) | ETHC306 | 81.86 | ETH009B01740200 | 68.73 | 9/24/2021 | Application Package | Ethanol | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | None | Retired |
| B017403 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California. | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETHCF206 | 38.58 | ETH012B01740300 | 29.14 | 9/24/2021 | Application Package | Ethanol - Cellulosic | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018701 | Tier 2 | 3.0 | Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional) | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01870100 | -435.22 | 9/30/2021 | Application Package | Bio-CNG | Dry Creek RNG LLC (C1098) | Dry Creek RNG Project (F00342) | Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| B021401 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional) | Utah | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B02140100 | -413.67 | 9/30/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Milford Farm (71483) | Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional) | None | Retired |
| B021901 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B02190100 | -412.71 | 9/30/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | HOMAN FARM (71343) | RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B016501 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional) | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020200 | -289.76 | CNG026B01650100 | -406.35 | 9/30/2021 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| B018501 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01850100 | -389.66 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B018502 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01850200 | -388.91 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | None | Retired |
| B019801 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01980100 | -388.29 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| A039401 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00360100 | 67.09 | ETH009A03940100 | 66.71 | 10/14/2021 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A039402 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A00360200 | 32.40 | ETH012A03940200 | 27.87 | 10/14/2021 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | None | Retired |
| A040201 | Tier 1 | 3.0 | Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00340100 | 66.23 | ETH009A04020100 | 63.73 | 10/11/2021 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | None | Retired |
| A037903 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional) | Texas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A03790300 | 64.00 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A037803 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A01610300 | 66.62 | ETH010A03780300 | 66.28 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A037805 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A01610500 | 74.57 | ETH010A03780500 | 73.81 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (70039) | Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | None | Retired |
| A042301 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETHC292 | 73.11 | ETH009A04230100 | 70.88 | 10/26/2021 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A042302 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04230200 | 24.02 | 10/26/2021 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional) | None | Retired |
| T1N-1769 | Tier 1 | 2.0 | Fuel Producer: Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: Fuel Producer: REG Seneca, LLC (80232) ; U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California | Illinois | Corn Oil | Biodiesel | None | None | BDC213 | 34.02 | 4/2/2018 | None | Biodiesel | REG Seneca, LLC (3652) | Fuel Producer: REG Seneca, LLC (80232) | U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California | None | Retired |
| A038001 | Tier 1 | 3.0 | Fuel Producer: GHI Energy, LLC (6156); Facility Name: Fort Bend Power Producers (shared facility) (7113s); Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG. | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A03800100 | 34.94 | 11/4/2021 | None | Bio-CNG | GHI Energy, LLC (6156) | Fort Bend Power Producers (shared facility) (7113s) | Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG. | None | Retired |
| A041601 | Tier 1 | 3.0 | Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04160100 | 66.18 | 11/23/2021 | None | Bio-CNG | TRUSTAR ENERGY LLC (6523) | Greentree Landfill Gas Company (F00212) | Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. | None | Retired |
| A042601 | Tier 1 | 3.0 | Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional) | Iowa | (animal and poultry fat | Biodiesel (BIO) | BDT211 | 31.19 | BIO002A04260100 | 29.23 | 12/22/2021 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional) | None | Retired |
| A042602 | Tier 1 | 3.0 | Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional) | Iowa | Soybean Oil (005) | Biodiesel (BIO) | BDS206 | 54.50 | BIO005A04260200 | 55.05 | 12/22/2021 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional) | None | Retired |
| B020701 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02070100 | -135.37 | 12/29/2021 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional) | None | Retired |
| B020702 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02070200 | -211.01 | 12/29/2021 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional) | None | Retired |
| B022001 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02200100 | -345.80 | CNG044B02200101 | -410.57 | 12/31/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | SOMERSET FARM (71381) | Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| B024001 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Distillers' Corn Oil (003 | Renewable Diesel (RND) | RND003B01930100 | None | RND003B02400100 | 29.79 | 12/28/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B024002 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Soybean Oil (005) | Renewable Diesel (RND) | RND005B01930200 | None | RND005B02400200 | 57.64 | 12/28/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024003 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | (animal and poultry fat | Renewable Diesel (RND) | None | None | RND002B02400300 | 33.34 | 12/28/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024004 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Distillers' Corn Oil (003 | Renewable Naphtha (RNT) | RNT003B01930300 | 34.90 | RNT003B02400400 | 29.79 | 12/28/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024005 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Soybean Oil (005) | Renewable Naphtha (RNT) | RNT005B01930400 | 64.24 | RNT005B02400500 | 57.64 | 12/28/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024006 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | oking Oil/Waste Oil (UC | Renewable Naphtha (RNT) | None | None | RNT001B02400600 | 21.09 | 12/28/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024007 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | (animal and poultry fat | Renewable Naphtha (RNT) | None | None | RNT002B02400700 | 33.34 | 12/28/2021 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024008 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | oking Oil/Waste Oil (UC | Renewable Diesel (RND) | None | None | RND001B02400800 | 21.09 | 12/28/2021 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | Retired |
| B024101 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | California | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B02410100 | 54.68 | 12/28/2021 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | None | Retired |
| B024103 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | California | Canola Oil (006) | Renewable Diesel (RND) | None | None | RND006B02410300 | 51.87 | 12/28/2021 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A043602 | Tier 1 | 3.0 | Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04360200 | 24.89 | 2/1/2022 | None | Ethanol | AL CORN CLEAN FUEL, LLC (4825) | AL CORN CLEAN FUEL, LLC (70087) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| B025101 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B02510100 | 60.13 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025102 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Distillers' Corn Oil (003 | Renewable Diesel (RND) | RND003B00540100 | 27.42 | RND003B02510200 | 27.64 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025103 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Diesel (RND) | RND001B00540200 | 19.92 | RND001B02510300 | 19.75 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025104 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Diesel (RND) | None | None | RND001B02510400 | 18.16 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025105 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Diesel (RND) | RND002B00540300 | 31.86 | RND002B02510500 | 32.14 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025106 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Diesel (RND) | None | None | RND002B02510600 | 42.48 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025107 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Soybean Oil (005) | Renewable Naphtha (RNT) | None | None | RNT005B02510700 | 60.13 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025108 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Distillers' Corn Oil (003 | Renewable Naphtha (RNT) | None | None | RNT003B02510800 | 27.64 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025109 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Naphtha (RNT) | None | None | RNT001B02510900 | 19.75 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025110 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Naphtha (RNT) | None | None | RNT001B02511000 | 18.16 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B025111 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Naphtha (RNT) | None | None | RNT002B02511100 | 32.14 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B025112 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Naphtha (RNT) | None | None | RNT002B02511200 | 42.48 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | None | Retired |
| B026801 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B00450100 | 25.08 | AJF002B02680100 | 18.87 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |
| B026802 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B00450200 | 25.08 | RND002B02680200 | 18.87 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026803 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B00450300 | 25.08 | RNT002B02680300 | 18.87 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B026810 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B01680100 | 33.42 | AJF002B02681000 | 29.26 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |
| B026811 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B01680200 | 33.42 | RND002B02681100 | 29.26 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026812 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B01680300 | 33.42 | RNT002B02681200 | 29.26 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B021601 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02160100 | -382.83 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | None | Retired |
| B021602 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | None | None | LNG026B02160200 | -369.56 | 3/30/2022 | Application Package | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional) | None | Retired |
| B021603 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN026B02160300 | -366.02 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional) | None | Retired |
| B021701 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02170100 | -303.92 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | None | Retired |
| B021702 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | None | None | LNG026B02170200 | -290.16 | 3/30/2022 | Application Package | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B021703 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN026B02170300 | -286.62 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional) | None | Retired |
| B026701 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | Distillers' Corn Oil (003 | Biodiesel (BIO) | BIO003A02850500 | 25.22 | BIO003B02670100 | 28.67 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | None | Retired |
| B026702 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | (animal and poultry fat | Biodiesel (BIO) | BIO002A02850600 | 30.94 | BIO002B02670200 | 32.53 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | None | Retired |
| B028001 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | California | Swine Manure (044) | Gaseous Hydrogen (HYG) | None | None | HYG044B02800100 | -374.14 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | None | Retired |
| B028002 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | California | Swine Manure (044) | Gaseous Hydrogen (HYG) | None | None | HYG044B02800200 | -390.47 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | None | Retired |
| A045501 | Tier 1 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086) ; Facility Name: Theresa Street Water Resource Recovery Facility (F00343); Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional) | Nebraska | Wastewater Sludge (030 | Compressed Natural Gas (CNG) | None | None | CNG030A04550100 | 43.12 | 4/14/2022 | None | Bio-CNG | BLUE SOURCE LLC (6086) | Theresa Street Water Resource Recovery Facility (F00343) | Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional) | None | Retired |
| B037802 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B03780200 | 75.16 | 12/19/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | None | Retired |
| A016501 | Tier 1 | 3.0 | Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California | Rhode Island | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A01650100 | 15.24 | BIO001A01650102 | 15.02 | 12/16/2019 | None | Biodiesel | NEWPORT BIODIESEL INC (7764) | NEWPORT BIODIESEL LLC (83532) | Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California | 2021 AFPR Recert Complete | Retired |
| B004303 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | None | None | RNT002B00430300 | 37.13 | 12/27/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| A016001 | Tier 1 | 3.0 | Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01600100 | 44.90 | CNG025A01600102 | 45.59 | 12/20/2019 | None | Bio-CNG | Iogen D3 Biofuel Partners LLC (6486) | GSF Energy-Rumpke Landfill (71138S) | Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | 2021 AFPR Recert Complete | Retired |
| A016502 | Tier 1 | 3.0 | Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California | Rhode Island | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A01650200 | 18.60 | BIO001A01650202 | 17.61 | 12/16/2019 | None | Biodiesel | NEWPORT BIODIESEL INC (7764) | NEWPORT BIODIESEL LLC (83532) | Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California | 2021 AFPR Recert Complete | Retired |
| B008901 | Tier 2 | 3.0 | Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00890101 | -126.52 | ELC026B00890103 | -93.58 | 3/25/2021 | None | Electricity | Gallo Cattle Company, LP (C1029) | Cottonwood Dairy (F00094) | Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029701 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Kansas | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02970101 | 58.34 | LNG025A02970102 | 60.50 | 12/15/2020 | None | Bio-LNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| B004301 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B00430100 | 37.13 | AJF002B00430102 | 38.93 | 12/27/2019 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B004403 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B00440300 | 42.91 | RNT002B00440302 | 44.72 | 12/27/2019 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California | 2021 AFPR Recert Complete | Retired |
| B016801 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B01680100 | 33.42 | AJF002B01680101 | 35.53 | 6/29/2021 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A006402 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00640200 | 68.04 | ETH009A00640200 | 64.75 | 5/7/2019 | None | Ethanol | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| None | Lookup Table | 3.0 | CARBOB - based on the average crude oil supplied to California refineries and average California refinery efficiencies | California | Crude Oil | CARBOB | None | None | CBO000L00072019 | 100.82 | NA | None | CARBOB | NA | NA | CARBOB based on the average crude oil supplied to California refineries and average California refinery efficiencies | None | |
| T1N-1734 | Tier 1 | 2.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California | Texas | Used Cooking Oil (UCO) | Biodiesel | BDU226 | 22.80 | BDU226R | 24.41 | 11/28/2018 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California | None | |
| A007701 | Tier 1 | 3.0 | Fuel Producer: Western Plains Energy, LLC (4740) ; Facility Name: Western Plains Energy, LLC (70030); Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California | Kansas | Corn (009) | Ethanol (ETH) | ETHC278 | 70.60 | ETH009A00770100 | 62.91 | 4/15/2019 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California | None | |
| A007702 | Tier 1 | 3.0 | Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Pathway Description: Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETHG215 | 78.55 | ETH010A00770200 | 66.64 | 4/15/2019 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California | None | |
| A003201 | Tier 1 | 3.0 | Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California | Mississippi | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU217 | 27.90 | BIO001A00320100 | 20.92 | 5/28/2019 | None | Biodiesel | Scott Petroleum Inc (4840) | Scott Petroleum Biodiesel Refinery (82908) | U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California | None | Retired |
| A003202 | Tier 1 | 3.0 | Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California | Mississippi | Distillers' Corn Oil (003) | Biodiesel (BIO) | None | None | BIO003A00320200 | 28.43 | 5/28/2019 | None | Biodiesel | Scott Petroleum Inc (4840) | Scott Petroleum Biodiesel Refinery (82908) | U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California | None | Retired |
| None | Lookup Table | 3.0 | ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies | NA | Crude Oil | Diesel | None | None | ULS000L00072019 | 100.45 | NA | None | Diesel | NA | NA | ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| None | Lookup Table | 3.0 | Compressed Natural Gas from Pipeline Average North Amer | NA | North American Fossil NG (031) | Compressed Natural Gas (CNG) | None | None | CNG000L00072019 | 79.21 | NA | None | Fossil CNG | NA | NA | Compressed Natural Gas from Pipeline Average North American Fossil Natural Gas | None | |
| None | Lookup Table | 3.0 | Fossil LPG from crude oil refining and natural gas processin | NA | Crude Oil | Propane (LPG) | None | None | LPG000L00072019 | 83.19 | NA | None | Propane | NA | NA | Fossil LPG from crude oil refining and natural gas processing used as a transport fuel | None | |
| None | Lookup Table | 3.0 | Electricity that is generated from 100 percent zero-CI source | NA | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | NA | None | Electricity | NA | NA | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| None | Lookup Table | 3.0 | Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | NA | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025L00072019 | 99.48 | NA | None | Hydrogen | NA | NA | Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| None | Lookup Table | 3.0 | Compressed H2 produced in California from central SMR of North American fossil-based NG | NA | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | NA | None | Hydrogen | NA | NA | Compressed H2 produced in California from central SMR of North American fossil-based NG | None | |
| None | Lookup Table | 3.0 | Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | NA | Zero-CI Sources (037) | Gaseous Hydrogen (HYG) | None | None | HYG037L00072019 | 10.51 | NA | None | Hydrogen | NA | NA | Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | None | |
| None | Lookup Table | 3.0 | Compressed H2 produced in California from electrolysis using California average grid electricity | NA | Grid Electricity (039) | Gaseous Hydrogen (HYG) | None | None | HYG039L00072019 | 164.46 | NA | None | Hydrogen | NA | NA | Compressed H2 produced in California from electrolysis using California average grid electricity | None | |
| None | Lookup Table | 3.0 | Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | NA | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025L00072019 | 129.09 | NA | None | Hydrogen | NA | NA | Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| None | Lookup Table | 3.0 | Liquefied H2 produced in California from central SMR of North American fossil-based NG | NA | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | NA | None | Hydrogen | NA | NA | Liquefied H2 produced in California from central SMR of North American fossil-based NG | None | |
| A008302 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | Minnesota | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A00830200 | 48.49 | 6/7/2019 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A008301 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | Minnesota | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A00830100 | 53.68 | 6/7/2019 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | None | Retired |
| A010001 | Tier 1 | 3.0 | Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC275 | 76.35 | ETH009A01000100 | 71.62 | 6/7/2019 | None | Ethanol | The Andersons, Inc (5872) | The Andersons Denison Ethanol (70135) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| None | Lookup Table | 3.0 | Fuel Producer: BMW of North America, LLC (C1033); Smart Charging Lookup Table Pathway | NA | Smart Charging or Smart Electrolysis (047) | Electricity (ELC) | None | None | NA | N/A | 6/30/2019 | See CI's | Electricity | BMW of North America, LLC (C1033) | NA | Smart Charging Lookup Table Pathway | None | |
| A012501 | Tier 1 | 3.0 | Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETHC285 | 83.47 | ETH009A01250100 | 75.16 | 8/6/2019 | None | Ethanol | Plymouth Energy LLC (5474) | Plymouth Energy LLC (70183) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California | None | |
| None | Lookup Table | 3.0 | Fuel Producer: Southern California Edison; Smart Charging Lookup Table Pathway | NA | Smart Charging or Smart Electrolysis (047) | Electricity (ELC) | None | None | NA | N/A | 9/30/2019 | See CI's | Electricity | Southern California Edison | NA | Smart Charging Lookup Table Pathway | None | |
| A014103 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | Missouri | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01410300 | 22.62 | 9/25/2019 | None | Biodiesel | High Plains Bioenergy (4846) | HPB - St. Joe Biodiesel LLC (80059) | Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | None | |
| A017401 | Tier 1 | 3.0 | Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETHC227 | 71.84 | ETH009A01740100 | 65.77 | 10/17/2019 | None | Ethanol | Nebraska Corn Processing (3516) | Nebraska Corn Processing LLC (70230) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California | None | Retired |
| A011701 | Tier 1 | 3.0 | Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Maracaí (70347); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A01170100 | 51.88 | 11/5/2019 | None | Ethanol | Raízen Tarumã S/A (3807) | Maracaí (70347) | Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California | None | |
| A015301 | Tier 1 | 3.0 | Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Tarumã (70338); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A01530100 | 56.35 | 11/5/2019 | None | Ethanol | Raízen Tarumã S/A (3807) | Tarumã (70338) | Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California | None | |
| A008201 | Tier 1 | 3.0 | Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) ; Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional) | California | Corn (009) | Ethanol (ETH) | ETHC316 | 63.01 | ETH009A00820100 | 58.95 | 12/17/2019 | None | Ethanol | GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) | GFP Ethanol, LLC dba Calgren Renewable Fuels (70317) | Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional) | None | |
| A016901 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional) | Arizona | Wastewater Sludge (030) | Liquefied Natural Gas (LNG) | None | None | LNG030A01690100 | 41.58 | 12/18/2019 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional) | None | Retired |
| A016902 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional) | Arizona | Wastewater Sludge (030) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN030A01690200 | 44.67 | 12/18/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional) | None | Retired |
| A011401 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA | Texas | Wastewater Sludge (030) | Liquefied Natural Gas (LNG) | None | None | LNG030A01140100 | 54.76 | 12/19/2019 | None | Bio-LNG | Element Markets Renewable Energy, LLC (5877) | Ameresco San Antonio Biogas (71204) | Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA | None | |
| A011402 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG | Texas | Wastewater Sludge (030) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN030A01140200 | 57.84 | 12/19/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ameresco San Antonio Biogas (71204) | Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A013502 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | Oklahoma | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A01350200 | 55.82 | 12/20/2019 | None | Biodiesel | High Plains Bioenergy (4846) | High Plains Bioenergy (82883) | Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | None | Retired |
| A013503 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | Oklahoma | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01350300 | 20.68 | 12/20/2019 | None | Biodiesel | High Plains Bioenergy (4846) | High Plains Bioenergy (82883) | Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | None | Retired |
| B003301 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (F00080); Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B00330100 | 153.17 | 12/31/2019 | Application Package | Hydrogen | CleanFuture, Inc. (C1001) | Air Products and Chemicals, Inc. (F00080) | Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts | None | |
| B003701 | Tier 2 | 3.0 | Fuel Producer: SMUD (S338); Facility Name: Van Warmerdam Dairy Digester (V4907); Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00370100 | -592.68 | 12/31/2019 | Application Package | Electricity | SMUD (S338) | Van Warmerdam Dairy Digester (V4907) | Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California | None | |
| B003801 | Tier 2 | 3.0 | Fuel Producer: SMUD (S338); Facility Name: Van Steyn Dairy Digester (V1125); Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00380100 | -630.72 | 12/31/2019 | Application Package | Electricity | SMUD (S338) | Van Steyn Dairy Digester (V1125) | Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California | None | |
| A016601 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California | Illinois | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF270 | 62.72 | CNG025A01660100 | 60.09 | 12/20/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California | None | |
| A016602 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations | Illinois | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNGLF228 | 76.13 | LNG025A01660200 | 80.27 | 12/20/2019 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations | None | |
| A016603 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG | Illinois | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | CNGLF271 | 78.68 | LCN025A01660300 | 83.36 | 12/20/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Milam High Btu Gas Plant (71208) | East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG | None | |
| B005001 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles. | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B00500100 | 153.36 | 1/13/2020 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles. | None | |
| L000301 | Lookup Table | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: CleanFuture (F00024); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | Oregon | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/28/2019 | None | Electricity | CleanFuture, Inc. (C1001) | CleanFuture (F00024) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L000701 | Lookup Table | 3.0 | Fuel Producer: EVgo Services LLC (C1101); Facility Name: EVgo Services LLC (F00033); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/3/2019 | None | Electricity | EVgo Services LLC (C1101) | EVgo Services LLC (F00033) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L001301 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018) ; Facility Name: SRECTrade, Inc. Zero CI Electricity (F00043); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 5/7/2019 | None | Electricity | SRECTrade, Inc (C1018) | SRECTrade, Inc. Zero CI Electricity (F00043) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L005901 | Lookup Table | 3.0 | Fuel Producer: Alameda Municipal Power (C1021); Facility Name: Alamedia Municipal Power (F00056); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/14/2019 | None | Electricity | Alameda Municipal Power (C1021) | Alameda Municipal Power (F00056) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L006501 | Lookup Table | 3.0 | Fuel Producer: ChargePoint, Inc. (C1028); Facility Name: Chargepoint, Inc. (F00061); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/27/2019 | None | Electricity | ChargePoint, Inc. (C1028) | Chargepoint, Inc. (F00061) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L007501 | Lookup Table | 3.0 | Fuel Producer: East Bay Community Energy Authority (C1022); Facility Name: East Bay Community Energy (F0054); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/25/2019 | None | Electricity | East Bay Community Energy Authority (C1022) | East Bay Community Energy (F0054) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L008101 | Lookup Table | 3.0 | Fuel Producer: BMW of North America, LLC (C1033); Facility Name: BMW of North America, LLC Corporate Headquarters (F00076); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | New Jersey | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/6/2019 | None | Electricity | BMW of North America, LLC (C1033) | BMW of North America, LLC Corporate Headquarters (F00076) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L008201 | Lookup Table | 3.0 | Fuel Producer: Port of Oakland (C1035); Facility Name: Port of Oakland (F00078); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/16/2019 | None | Electricity | Port of Oakland (C1035) | Port of Oakland (F00078) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L008301 | Lookup Table | 3.0 | Fuel Producer: Jaguar Land Rover North America, LLC (C1032); Facility Name: Jaguar Land Rover North America, LLC (F00083); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | New Jersey | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/29/2019 | None | Electricity | Jaguar Land Rover North America, LLC (C1032) | Jaguar Land Rover North America, LLC (F00083) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L008701 | Lookup Table | 3.0 | Fuel Producer: Sonoma Clean Power Authority (C1012); Facility Name: Golden Hills North Wind Energy Center (F00087); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/29/2019 | None | Electricity | Sonoma Clean Power Authority (C1012) | Golden Hills North Wind Energy Center (F00087) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L009001 | Lookup Table | 3.0 | Fuel Producer: Beyond Energy, LLC (C1041); Facility Name: Beyond Energy, LLC (F00090); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/25/2019 | None | Electricity | Beyond Energy, LLC (C1041) | Beyond Energy, LLC (F00090) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L009301 | Lookup Table | 3.0 | Fuel Producer: Bridge to Renewables, Benefit LLC (C1006); Facility Name: Bridge to Renewables Corporate Headquarters (F00099); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | Washington D.C. | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/3/2019 | None | Electricity | Bridge to Renewables, Benefit LLC (C1006) | Bridge to Renewables Corporate Headquarters (F00099) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L009801 | Lookup Table | 3.0 | Fuel Producer: San Deigo Metropolitan Transit Center (S304); Facility Name: San Deigo Metropolitan Transit System (F00106); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/3/2019 | None | Electricity | San Deigo Metropolitan Transit Center (S304) | San Deigo Metropolitian Transit System (F00106) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L009901 | Lookup Table | 3.0 | Fuel Producer: SMUD (S338); Facility Name: Sacramento Municipal Utility District (F00116); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/3/2019 | None | Electricity | SMUD (S338) | Sacramento Municipal Utility District (F00116) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L010001 | Lookup Table | 3.0 | Fuel Producer: Smart Charging Technologies (C1050); Facility Name: Smart Charging Technologies 0CI (F00122); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | Florida | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/17/2019 | None | Electricity | Smart Charging Technologies (C1050) | Smart Charging Technologies 0CI (F00122) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L010101 | Lookup Table | 3.0 | Fuel Producer: Enel X North America, Inc. (C1051); Facility Name: Enel X North America - eMobility (F00124); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | Massachusetts | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/18/2019 | None | Electricity | Enel X North America, Inc. (C1051) | Enel X North America - eMobility (F00124) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L010201 | Lookup Table | 3.0 | Fuel Producer: JC Sales (C1031); Facility Name: JC Sales (F00125); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/18/2019 | None | Electricity | JC Sales (C1031) | JC Sales (F00125) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L010401 | Lookup Table | 3.0 | Fuel Producer: Volta Industries, Inc. (C1025); Facility Name: Volta Industries, Inc. (F00115); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 1/10/2020 | None | Electricity | Volta Industries, Inc. (C1025) | Volta Industries, Inc. (F00115) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| B001901 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00190100 | -352.89 | 11/14/2019 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Open Sky (F00007) | Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California | None | Retired |
| L009501 | Lookup Table | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied H2 produced in California from central SMR of North American fossil-based NG | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 12/17/2019 | None | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied H2 produced in California from central SMR of North American fossil-based NG | None | |
| L009701 | Lookup Table | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025L00072019 | 129.09 | 12/4/2019 | None | Hydrogen | FirstElement Fuel (E426) | Air Products & Chemicals SMR Sacramento (F00069) | Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| L005801 | Lookup Table | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025L00072019 | 99.48 | 7/16/2019 | None | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Air Products Central SMR (F00051) | Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| L005701 | Lookup Table | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of North American fossil-based NG | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | 7/16/2019 | None | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Air Products Central SMR (F00051) | Compressed H2 produced in California from central SMR of North American fossil-based NG | None | |
| L007601 | Lookup Table | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025L00072019 | 99.48 | 7/12/2019 | None | Hydrogen | Shell Energy North America (6154) | Carson Hydrogen Plant (F00059) | Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| L007701 | Lookup Table | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025L00072019 | 99.48 | 7/12/2019 | None | Hydrogen | FirstElement Fuel (E426) | Air Products and Chemicals SMR Wilmington. CA (F00068) | Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills | None | |
| L008901 | Lookup Table | 3.0 | Fuel Producer: San Francisco Public Utilities Commission (C1003); Facility Name: R.C. Kirkwood Power House Units #1, #2, #3 (F00089); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/27/2019 | None | Electricity | San Francisco Public Utilities Commission (C1003) | R.C. Kirkwood Power House Units #1, #2, #3 (F00089) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L009401 | Lookup Table | 3.0 | Fuel Producer: Oxnard Harbor District (C1030); Facility Name: Oxnard Harbor District (F00105); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/30/2019 | None | Electricity | Oxnard Harbor District (C1030) | Oxnard Harbor District (F00105) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L010301 | Lookup Table | 3.0 | Fuel Producer: Grant Farm dba Momentum Zero CI Electricity (C1054); Facility Name: Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 2/11/2020 | None | Electricity | Grant Farm dba Momentum Zero CI Electricity (C1054) | Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L010501 | Lookup Table | 3.0 | Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: 3Degrees Group, Inc. (F00137); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/9/2020 | None | Electricity | 3Degrees Group, Inc. (C1055) | 3Degrees Group, Inc. (F00137) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L010801 | Lookup Table | 3.0 | Fuel Producer: Cruise LLC (C1064); Facility Name: Cruise Corporate Headquarters (F00144); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/30/2020 | None | Electricity | Cruise LLC (C1064) | Cruise Corporate Headquarters (F00144) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L010601 | Lookup Table | 3.0 | Fuel Producer: Energy Mission Control (C1058); Facility Name: Energy Mission Control (F00142); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/27/2020 | None | Electricity | Energy Mission Control (C1058) | Energy Mission Control (F00142) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| A019702 | Tier 1 | 3.0 | Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | Iowa | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A01970200 | 55.00 | 6/16/2020 | None | Biodiesel | IOWA RENEWABLE ENERGY LLC (4698) | IOWA RENEWABLE ENERGY LLC (82854) | Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | None | |
| A019703 | Tier 1 | 3.0 | Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | Iowa | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A01970300 | 30.23 | 6/16/2020 | None | Biodiesel | IOWA RENEWABLE ENERGY LLC (82854) | IOWA RENEWABLE ENERGY LLC (82854) | Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | None | |
| A019704 | Tier 1 | 3.0 | Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | Iowa | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A01970400 | 19.34 | 6/16/2020 | None | Biodiesel | IOWA RENEWABLE ENERGY LLC (82854) | IOWA RENEWABLE ENERGY LLC (82854) | Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | None | |
| A020701 | Tier 1 | 3.0 | Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02070100 | 38.07 | 6/16/2020 | None | Bio-CNG | MEM RNG, LLC (2141) | Blue Ridge Landfill, LLC (F00132) | Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional) | None | Retired |
| A019701 | Tier 1 | 3.0 | Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698); Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | Iowa | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A01970100 | 49.91 | 6/16/2020 | None | Biodiesel | IOWA RENEWABLE ENERGY LLC (4698) | IOWA RENEWABLE ENERGY LLC (82854) | Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California | None | |
| A021801 | Tier 1 | 3.0 | Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional) | Washington | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A02180100 | 37.19 | 6/22/2020 | None | Bio-CNG | PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080) | H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301) | Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional) | None | Retired |
| B009803 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980300 | -192.49 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional) | None | Retired |
| B009804 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B00980400 | -323.10 | 6/30/2020 | Application Package | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A023801 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | Canada | Canola Oil (006) | Biodiesel (BIO) | BDCA200L | 57.39 | BIO006A02380100 | 54.22 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | None | |
| A023802 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | Canada | Soybean Oil (005) | Biodiesel (BIO) | BDS200L | 56.03 | BIO005A02380200 | 59.63 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | None | |
| A023803 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | Canada | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC200L | 32.8 | BIO003A02380300 | 30.86 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | None | |
| A023804 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | Canada | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT200L | 34.97 | BIO002A02380400 | 34.92 | 7/27/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | None | |
| A023806 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | Canada | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A02380600 | 27.09 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California | None | |
| A023807 | Tier 1 | 3.0 | Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | Canada | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU218 | 22.38 | BIO001A02380700 | 22.88 | 7/24/2020 | None | Biodiesel | Biox Canada Limited (3758) | BIOX Canada Limited (80236) | US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | None | |
| A017101 | Tier 1 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNGDD201 | -254.94 | CNG026A01710100 | -329.76 | 12/24/2019 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Fair Oaks Upgrader, LLC (71001) | Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California | None | Retired |
| L010901 | Lookup Table | 3.0 | Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California | California | Zero-CI Sources Supplied via Green Tariff (048) | Electricity (ELC) | None | None | ELC048L00072019 | 0.00 | 5/12/2020 | None | Electricity | Marin Clean Energy (C1066) | Marin Clean Energy (F00147) | Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California | None | |
| L011201 | Lookup Table | 3.0 | Fuel Producer: City of Anaheim, Public Utilities Department (C1068); Facility Name: City of Anaheim, Public Utilities Department (F00157); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/30/2020 | None | Electricity | City of Anaheim, Public Utilities Department (C1068) | City of Anaheim, Public Utilities Department (F00157) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L011501 | Lookup Table | 3.0 | Fuel Producer: Powerflex (P343); Facility Name: PowerFlex Systems (F00162); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/30/2020 | None | Electricity | Powerflex (P343) | PowerFlex Systems (F00162) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L011601 | Lookup Table | 3.0 | Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 5/14/2020 | None | Electricity | Marin Clean Energy (C1066) | Marin Clean Energy (F00147) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L011801 | Lookup Table | 3.0 | Fuel Producer: Wonderful Renewable Energy, LLC (C1080); Facility Name: Wonderful Renewable Energy, LLC (F00170); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/1/2020 | None | Electricity | Wonderful Renewable Energy, LLC (C1080) | Wonderful Renewable Energy, LLC (F00170) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L012001 | Lookup Table | 3.0 | Fuel Producer: 3 Phases Renewables Inc. (P306); Facility Name: 3 Phases Renewables Inc. (P1225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/10/2020 | None | Electricity | 3 Phases Renewables Inc. (P306) | 3 Phases Renewables Inc. (P1225) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L012201 | Lookup Table | 3.0 | Fuel Producer: PowerFlex Systems, INC (C1092); Facility Name: PowerFlex Systems, Inc (F00197); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/30/2020 | None | Electricity | PowerFlex Systems, INC (C1092) | PowerFlex Systems, Inc (F00197) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L012101 | Lookup Table | 3.0 | Fuel Producer: San Diego Unified Port District (C1026); Facility Name: Port of San Diego (F00057); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/30/2020 | None | Electricity | San Diego Unified Port District (C1026) | Port of San Diego (F00057) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L012301 | Lookup Table | 3.0 | Fuel Producer: Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied H2 produced in California from central SMR of North American fossil-based NG | Canada | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 6/30/2020 | None | Hydrogen | 3Degrees Group, Inc. (C1055) | Praxair - Ontario, CA (F00208) | Liquefied H2 produced in California from central SMR of North American fossil-based NG | None | |
| L012401 | Lookup Table | 3.0 | Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using California average grid electricity | California | Grid Electricity (039) | Gaseous Hydrogen (HYG) | None | None | HYG039L00072019 | 164.46 | 8/11/2020 | None | Hydrogen | Cal State LA (C1063) | Cal State LA Hydrogen Research and Fueling Facility (F00145) | Compressed H2 produced in California from electrolysis using California average grid electricity | None | |
| L012701 | Lookup Table | 3.0 | Fuel Producer: Pacific Merchant Shipping Association (C1099); Facility Name: Pacific Merchant Shipping Association (F00220); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/10/2020 | None | Electricity | Pacific Merchant Shipping Association (C1099) | Pacific Merchant Shipping Association (F00220) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L010701 | Lookup Table | 3.0 | Fuel Producer: CSG EV LLC (C1060); Facility Name: CSG EV LLC (F00141); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 5/6/2020 | None | Electricity | CSG EV LLC (C1060) | CSG EV LLC (F00141) | Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California | None | |
| L011401 | Lookup Table | 3.0 | Fuel Producer: PCS Energy (C1070); Facility Name: PCS Energy (F00159); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 5/13/2020 | None | Electricity | PCS Energy (C1070) | PCS Energy (F00159) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L013501 | Lookup Table | 3.0 | Fuel Producer: Eco Credit Traders LLC (C1107); Facility Name: Eco Credit Traders LLC (F00234); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/14/2020 | None | Electricity | Eco Credit Traders LLC (C1107) | Eco Credit Traders LLC (F00234) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L013101 | Lookup Table | 3.0 | Fuel Producer: Element Markets EV, LLC (C1093) ; Facility Name: Element Markets EV, LLC (F00232); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | Texas | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/18/2020 | None | Electricity | Element Markets EV, LLC (C1093) | Element Markets EV, LLC (F00232) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A020101 | Tier 1 | 3.0 | Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail | Michigan | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU248 | 20.9 | BIO001A02010100 | 15.80 | 9/29/2020 | None | Biodiesel | Thumb BioEnergy (3862) | Thumb BioEnergy (03862) | Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail | None | Retired |
| A027801 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764) ; Facility Name: Aberdeen Energy (70299); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETHC237L | 80.19 | ETH009A02780100 | 71.77 | 10/9/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Aberdeen Energy (70299) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024702 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations | Michigan | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A02470200 | 62.68 | 10/13/2020 | None | Bio-LNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations | None | Retired |
| A024703 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | California | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A02470300 | 65.77 | 10/13/2020 | None | Bio-CNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | None | Retired |
| A025904 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A02590400 | 31.60 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | None | Retired |
| L013001 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI HYER (F00226); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | California | Zero-CI Sources (037) | Gaseous Hydrogen (HYG) | None | None | HYG037L00072019 | 10.51 | 9/30/2020 | None | Hydrogen | SRECTrade, Inc (C1018) | SRECTrade, Inc. Zero CI HYER (F00226) | Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | None | |
| L013301 | Lookup Table | 3.0 | Fuel Producer: Element Markets EV, LLC (C1093); Facility Name: 32-505 Harry Oliver Trail (F00233); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | California | Zero-CI Sources (037) | Gaseous Hydrogen (HYG) | None | None | HYG037L00072019 | 10.51 | 7/1/2020 | None | Hydrogen | Element Markets EV, LLC (C1093) | 32-505 Harry Oliver Trail (F00233) | Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources | None | |
| L013701 | Lookup Table | 3.0 | Fuel Producer: MYNT SYSTEMS (C1112); Facility Name: MYNT SYSTEMS (F00294); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 11/2/2020 | None | Electricity | MYNT SYSTEMS (C1112) | MYNT SYSTEMS (F00294) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| B011301 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C104); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles. | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B01130100 | 131.51 | 11/12/2020 | Application Package | Hydrogen | Iwatani Corporation of America (C104) | Linde-Praxair (F00088) | Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles. | None | |
| A028401 | Tier 1 | 3.0 | Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | Canada | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02380800 | 22.81 | BIO001A02840100 | 22.40 | 11/12/2020 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California. | None | |
| L013801 | Lookup Table | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of North American fossil-based NG | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | 11/12/2020 | None | Hydrogen | FirstElement Fuel (E426) | Air Products and Chemicals SMR Wilmington. CA (F00068) | Compressed H2 produced in California from central SMR of North American fossil-based NG | None | |
| L013901 | Lookup Table | 3.0 | Fuel Producer: Penske Truck Leasing, Co., L.P. (C1116); Facility Name: Penske Truck Leasing (F00310); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 11/25/2020 | None | Electricity | Penske Truck Leasing, Co., L.P. (C1116) | Penske Truck Leasing (F00310) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L014001 | Lookup Table | 3.0 | Fuel Producer: NFI Industries (C1117); Facility Name: NFI Industries (F00311); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 11/25/2020 | None | Electricity | NFI Industries (C1117) | NFI Industries (F00311) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A028001 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Glacial Lakes Energy (70064); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETHC241L | 79.21 | ETH009A02800100 | 72.66 | 12/8/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Glacial Lakes Energy (70064) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B002401 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B00240100 | -525.14 | 12/10/2020 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Coronado Dairy Farm (F00009) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California | None | Retired |
| A028301 | Tier 1 | 3.0 | Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California | Canada | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A02380500 | 36.98 | BIO002A02830100 | 28.29 | 12/15/2020 | None | Biodiesel | BIOX Canada Limited (3758) | BIOX Canada Limited (80236) | Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California | None | |
| L014301 | Lookup Table | 3.0 | Fuel Producer: The Regents of the University of California (C1121); Facility Name: The Regents of the University of California (F00324); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California | California | Zero-CI Sources Supplied via Green Tariff (048) | Electricity (ELC) | None | None | ELC048L00072019 | 0.00 | 12/28/2020 | None | Electricity | The Regents of the University of California (C1121) | The Regents of the University of California (F00324) | Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California | None | |
| L014401 | Lookup Table | 3.0 | Fuel Producer: S. C. Valley Transportation Authority (C1119); Facility Name: S.C. Valley Transportation Authority (F00328); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/24/2020 | None | Electricity | S. C. Valley Transportation Authority (C1119) | S.C. Valley Transportation Authority (F00328) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L014801 | Lookup Table | 3.0 | Fuel Producer: Toyota Motor North America (C1069); Facility Name: Toyota Motor North America (F00338); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 2/16/2021 | None | Electricity | Toyota Motor North America (C1069) | Toyota Motor North America (F00338) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L015001 | Lookup Table | 3.0 | Fuel Producer: Redwood Coast Energy Authority (R704); Facility Name: Redwood Coast Energy Authority (F00031); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 2/24/2021 | None | Electricity | Redwood Coast Energy Authority (R704) | Redwood Coast Energy Authority (F00031) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L015201 | Lookup Table | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. Venture, Inc. (F00345); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 2/24/2021 | None | Electricity | U.S. Venture, Inc. (5504) | U.S. Venture, Inc. (F00345) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A033002 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00990200 | 63.23 | ETH009A03300200 | 63.46 | 3/1/2021 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A033003 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03300300 | 25.32 | 3/1/2021 | None | Ethanol - Cellulosic | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional) | None | Retired |
| L015101 | Lookup Table | 3.0 | Fuel Producer: PineSpire, LLC (C1128); Facility Name: PineSpire (F00344); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/4/2021 | None | Electricity | PineSpire, LLC (C1128) | PineSpire (F00344) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A028701 | Tier 1 | 3.0 | Fuel Producer: Elkhorn Valley Ethanol LLC (4833); Facility Name: Elkhorn Valley Ethanol LLC (70095); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI | Nebraska | Corn (009) | Ethanol (ETH) | T1N-1277, T1N-1276 | 74.74, 79.83 | ETH009A02870100 | 71.99 | 3/22/2021 | None | Ethanol | Elkhorn Valley Ethanol LLC (4833) | Elkhorn Valley Ethanol LLC (70095) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI | None | Retired |
| A031001 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional) | Louisiana | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A03100100 | 41.18 | 3/18/2021 | None | Bio-CNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B011101 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Stotz Dairy Southern (F00155); Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging | Arizona | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01110100 | -762.09 | 3/23/2021 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Stotz Dairy Southern (F00155) | Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging | None | Retired |
| B012301 | Tier 2 | 3.0 | Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling | California | Food Scraps/Waste (027) | Compressed Natural Gas (CNG) | None | None | CNG027B01230100 | -79.91 | 3/29/2021 | Application Package | Bio-CNG | South San Francisco Scavengers (S283) | South San Francisco Scavenger Company (J0500) | Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling | None | |
| B012302 | Tier 2 | 3.0 | Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling | California | Other Organic Waste (029) | Compressed Natural Gas (CNG) | None | None | CNG028B01230200 | 0.28 | 3/29/2021 | Application Package | Bio-CNG | South San Francisco Scavengers (S283) | South San Francisco Scavenger Company (J0500) | Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling | None | |
| A027601 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF261R | 52.14 | CNG025A02760100 | 47.41 | 3/25/2021 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Meadow Branch Landfill Gas Processing Facility (71252) | Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional) | None | Retired |
| B014802 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Triple G Dairy (F00156); Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California. | Arizona | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01480200 | -493.57 | 3/30/2021 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Triple G Dairy (F00156) | Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California. | None | Retired |
| B017201 | Tier 2 | 3.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional) | California | Corn (009) | Ethanol (ETH) | ETH009A00940100 | 67.03 | ETH009B01720100 | 65.68 | 3/29/2021 | Application Package | Ethanol | Aemetis Advanced Fuels Keyes, Inc (3566) | Aemetis Advanced Fuels Keyes, Inc (70234) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional) | None | Retired |
| B013302 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B01330200 | 32.50 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013303 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B01330300 | 25.50 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013304 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B01330400 | 20.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013305 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B01330500 | 26.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013307 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01330700 | 37.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B013308 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01330800 | 38.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B013309 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B01330900 | 43.00 | 4/30/2021 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional) | None | Retired |
| A029503 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A02950300 | 33.86 | 4/1/2021 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | None | |
| B018901 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | None | None | RNT003B01890100 | 33.00 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018902 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01890200 | 37.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018903 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT002B01890300 | 26.00 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018904 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B01890400 | 20.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018905 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B01890500 | 26.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018906 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01890600 | 38.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018907 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B01890700 | 43.50 | 4/30/2021 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018910 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891000 | 33.00 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018911 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891100 | 26.00 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018912 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891200 | 20.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018913 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891300 | 26.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018914 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891400 | 37.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018915 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891500 | 38.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| B018916 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B01891600 | 43.50 | 4/30/2021 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional) | None | Retired |
| A023901 | Tier 1 | 3.0 | Fuel Producer: M&N Participações S/A (C1082); Facility Name: Usina Giasa Ltda (F00192); Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A02390100 | 48.82 | 5/7/2021 | None | Ethanol | M&N Participações S/A (C1082) | Usina Giasa Ltda (F00192) | Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker. | None | Retired |
| A028801 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | Iowa | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A02880100 | 58.00 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | None | |
| A028802 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail. | Iowa | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A02880200 | 54.00 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail. | None | |
| A028803 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail. | Iowa | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC208 | 34.10 | BIO003A02880300 | 28.50 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail. | None | |
| A028804 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | Iowa | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU223 | 22.50 | BIO001A02880400 | 21.00 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | None | |
| A028805 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | Iowa | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU235 | 15.49 | BIO001A02880500 | 16.00 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | None | |
| A028806 | Tier 1 | 3.0 | Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | Iowa | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT212 | 35.94 | BIO002A02880600 | 33.50 | 5/11/2021 | None | Biodiesel | REG Newton, LLC (3514) | REG Newton, LLC (80162) | U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail. | None | |
| A029601 | Tier 1 | 3.0 | Fuel Producer: Green Plains Central City (3368); Facility Name: Green Plains Central City LLC (70141); Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California. | Nebraska | Corn (009) | Ethanol (ETH) | ETHC023 (T1R-1214) | 82.17 | ETH009A02960100 | 65.97 | 5/7/2021 | None | Ethanol | Green Plains Central City (3368) | Green Plains Central City LLC (70141) | Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A030903 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A03090300 | 68.76 | 5/4/2021 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A036701 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A03670100 | 49.53 | 5/11/2021 | None | Bio-CNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A028901 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC215 | 35.13 | BIO003A02890100 | 29.00 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | |
| A028902 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT220 | 36.80 | BIO002A02890200 | 33.50 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | |
| A028903 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A02890300 | 53.00 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | |
| A028904 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A02890400 | 58.30 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | |
| A028905 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU249 | 22.58 | BIO001A02890500 | 21.50 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | Retired |
| A028906 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU250 | 17.33 | BIO001A02890600 | 17.00 | 6/7/2021 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | None | |
| A036101 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A03610100 | 70.52 | 6/7/2021 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A036102 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A03610200 | 63.38 | 6/7/2021 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A036103 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03610300 | 23.59 | 6/7/2021 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A029001 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail | Illinois | Distillers' Corn Oil (003) | Biodiesel (BIO) | BDC213 | 34.02 | BIO003A02900100 | 28.00 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029004 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU242 | 21.84 | BIO001A02900400 | 20.75 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | None | Retired |
| A029005 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU244 | 16.57 | BIO001A02900500 | 16.25 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail | None | Retired |
| A029007 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail | Illinois | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT219 | 35.79 | BIO002A02900700 | 32.75 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail | None | |
| L001701 | Lookup Table | 3.0 | Fuel Producer: Tesla, Inc. (C1016); Facility Name: Tesla, Inc. (F00045); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 5/29/2019 | None | Electricity | Tesla, Inc. (C1016) | Tesla, Inc. (F00045) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L006301 | Lookup Table | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of North American fossil-based NG. | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | 7/12/2019 | None | Hydrogen | Shell Energy North America (6154) | Carson Hydrogen Plant (F00059) | Compressed H2 produced in California from central SMR of North American fossil-based NG. | None | |
| L007801 | Lookup Table | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills. | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025L00072019 | 129.09 | 7/16/2019 | None | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | Praxair Liquid H2 Source (F00053) | Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills. | None | |
| L007901 | Lookup Table | 3.0 | Fuel Producer: American Honda Motor Co., Inc. (C1023); Facility Name: American Honda Motor Co., Inc. (F00074); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/6/2019 | None | Electricity | American Honda Motor Co., Inc. (C1023) | American Honda Motor Co., Inc. (F00074) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L009101 | Lookup Table | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (SFS) (F00092); Liquefied H2 produced in California from central SMR of North American fossil-based NG. | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 9/26/2019 | None | Hydrogen | CleanFuture, Inc. (C1001) | Air Products and Chemicals, Inc. (SFS) (F00092) | Liquefied H2 produced in California from central SMR of North American fossil-based NG. | None | |
| L009201 | Lookup Table | 3.0 | Fuel Producer: Air Products and Chemicals, Inc. (C1042); Facility Name: APCI Wilmington Transfill (F00095); Compressed H2 produced in California from central SMR of North American fossil-based NG. | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | 9/27/2019 | None | Hydrogen | Air Products and Chemicals, Inc. (C1042) | APCI Wilmington Transfill (F00095) | Compressed H2 produced in California from central SMR of North American fossil-based NG. | None | |
| L009601 | Lookup Table | 3.0 | Fuel Producer: Paired Power (P995); Facility Name: McCalmont Engineering (22575); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | California | Directly Supplied Zero-CI Sources (049) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 3/30/2020 | None | Electricity | Paired Power (P995) | McCalmont Engineering (22575) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | None | |
| L011301 | Lookup Table | 3.0 | Fuel Producer: Trillium USA Company, LLC (C1056); Facility Name: Trillium USA Company, LLC (F00152); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | Texas | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/30/2020 | None | Electricity | Trillium USA Company, LLC (C1056) | Trillium USA Company, LLC (F00152) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L012501 | Lookup Table | 3.0 | Fuel Producer: Green Commuter (C1096) ; Facility Name: Green Commuter (F00214); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/8/2020 | None | Electricity | Green Commuter (C1096) | Green Commuter (F00214) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L012601 | Lookup Table | 3.0 | Fuel Producer: EV CHARGING SOLUTIONS, INC. (C1095); Facility Name: EV Charging Solutions, Inc. (F00215); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/8/2020 | None | Electricity | EV CHARGING SOLUTIONS, INC. (C1095) | EV Charging Solutions, Inc. (F00215) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L012801 | Lookup Table | 3.0 | Fuel Producer: Ingram Micro, Inc. (C1102); Facility Name: Ingram Micro, Inc. (F00222); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/25/2020 | None | Electricity | Ingram Micro, Inc. (C1102) | Ingram Micro, Inc. (F00222) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L012901 | Lookup Table | 3.0 | Fuel Producer: Zeco Systems Inc. d/b/a Greenlots (C1097) ; Facility Name: Zeco Systems Inc. d/b/a Greenlots (F00225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/11/2020 | None | Electricity | Zeco Systems Inc. d/b/a Greenlots (C1097) | Zeco Systems Inc. d/b/a Greenlots (F00225) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L013601 | Lookup Table | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Shell Energy North America (F00017); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | Texas | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 10/16/2020 | None | Electricity | Shell Energy North America (6154) | Shell Energy North America (F00017) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L014101 | Lookup Table | 3.0 | Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquified H2 produced in California from central SMR of North American fossil-based NG. | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 12/7/2020 | None | Hydrogen | 3Degrees Group, Inc. (C1055) | Praxair - Ontario, CA (F00208) | Liquefied H2 produced in California from central SMR of North American fossil-based NG. | None | |
| L015301 | Lookup Table | 3.0 | Fuel Producer: Green Water and Power (C1123); Facility Name: Green Water and Power (F00322); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/15/2021 | None | Electricity | Green Water and Power (C1123) | Green Water and Power (F00322) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L015501 | Lookup Table | 3.0 | Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #334 (F00358); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | California | Directly Supplied Zero-CI Sources (049) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 5/25/2021 | None | Electricity | City of Santa Clara/Silicon Valley Power (C1130) | BEAM EVARC Unit #334 (F00358) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | None | |
| L015401 | Lookup Table | 3.0 | Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #333 (F00357); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | California | Directly Supplied Zero-CI Sources (049) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 5/25/2021 | None | Electricity | City of Santa Clara/Silicon Valley Power (C1130) | BEAM EVARC Unit #333 (F00357) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | None | |
| L015601 | Lookup Table | 3.0 | Fuel Producer: San Jose Clean Energy (C1120); Facility Name: San Jose Clean Energy (F00323); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California. | California | Zero-CI Sources Supplied via Green Tariff (048) | Electricity (ELC) | None | None | ELC048L00072019 | 0.00 | 4/30/2021 | None | Electricity | San Jose Clean Energy (C1120) | San Jose Clean Energy (F00323) | Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California. | None | |
| L015701 | Lookup Table | 3.0 | Fuel Producer: AMPLY Power, Inc. (C1134); Facility Name: AMPLY Power, Inc (F00364); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 4/21/2021 | None | Electricity | AMPLY Power, Inc. (C1134) | AMPLY Power, Inc (F00364) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L015801 | Lookup Table | 3.0 | Fuel Producer: Muza Energy (C1136); Facility Name: Muza Energy (F00369); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/3/2021 | None | Electricity | Muza Energy (C1136) | Muza Energy (F00369) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A030201 | Tier 1 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF276 | 40.63 | CNG025A03020100 | 34.00 | 6/16/2021 | None | Bio-CNG | Shell Energy North America (6154) | Melissa Renewables, LLC (71407) | Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029101 | Tier 1 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNGLF272 | 39.83 | CNG025A02910100 | 34.17 | 6/16/2021 | None | Bio-CNG | Shell Energy North America (6154) | Pine Hill Renewables, LLC (71288) | Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A034502 | Tier 1 | 3.0 | Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations | Michigan | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNGLF200LR | 54.14 | LNG025A03450200 | 65.55 | 6/16/2021 | None | Bio-LNG | WESTSIDE GAS PRODUCERS, LLC (6218) | WESTSIDE GAS PRODUCERS, LLC (71151) | Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations | None | |
| A034503 | Tier 1 | 3.0 | Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations | Michigan | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | CNGLF223LR | 57.29 | LCN025A03450300 | 68.64 | 6/16/2021 | None | Bio-CNG | WESTSIDE GAS PRODUCERS, LLC (6218) | WESTSIDE GAS PRODUCERS, LLC (71151) | Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations | None | |
| A037301 | Tier 1 | 3.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail. | Texas | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU226R | 24.41 | BIO001A03730100 | 18.30 | 6/21/2021 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail. | None | |
| A037302 | Tier 1 | 3.0 | Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail. | Texas | Soybean Oil (005) | Biodiesel (BIO) | BDS210R | 53.43 | BIO005A03730200 | 53.55 | 6/21/2021 | None | Biodiesel | Global Alternative Fuels, LLC (7765) | Global Alternative Fuels, LLC (83533) | Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail. | None | |
| L015901 | Lookup Table | 3.0 | Fuel Producer: Sol Systems LLC (C1133); Facility Name: Sol Systems, LLC (F00370); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | Washington D.C. | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/21/2021 | None | Electricity | Sol Systems LLC (C1133) | Sol Systems, LLC (F00370) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| B017907 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | Singapore | Distillers' Corn Oil (003) | Renewable Diesel (RND) | RDC200L | 37.39 | RND003B01790700 | 36.43 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | None | |
| B017904 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | Singapore | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RDU201L | 25.61 | RND001B01790400 | 32.83 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | None | |
| B017906 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | Singapore | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B01790600 | 28.64 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California. | None | |
| B017905 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | Singapore | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RDU200L | 16.89 | RND001B01790500 | 24.29 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | None | |
| B017902 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | Singapore | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RDT201L | 34.19 | RND002B01790200 | 40.10 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | None | |
| B017903 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | Singapore | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RDT200L | 36.83 | RND002B01790300 | 38.26 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B017901 | Tier 2 | 3.0 | Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | Singapore | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RDT202 | 39.06 | RND002B01790100 | 42.77 | 6/25/2021 | Application Package | Renewable Diesel | Neste Singapore Pte Ltd (4137) | Neste Singapore (80327) | Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA. | None | |
| B014001 | Tier 2 | 3.0 | Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: New Energy One (F00274); Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California | Idaho | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01400100 | -698.21 | 6/29/2021 | Application Package | Electricity | Degrees3 Transportation Solutions, LLC (C1111) | New Energy One (F00274) | Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California | None | |
| B013901 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B00110100 | -372.35 | CNG044B01390100 | -431.79 | 6/29/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ruckman Farm (71256) | Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations | None | |
| B014101 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B00090100 | -323.83 | CNG044B01410100 | -449.66 | 6/29/2021 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Locust Ridge Farm (71298) | Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas | None | |
| B016601 | Tier 2 | 3.0 | Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01660100 | -750.81 | 6/28/2021 | Application Package | Electricity | SMUD (S338) | New Hope Dairy Digester (F00255) | Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional) | None | Retired |
| A033901 | Tier 1 | 3.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM221 | 46.34 | ETH018A03390100 | 48.08 | 6/30/2021 | None | Ethanol | BIOSEV S.A. (3869) | Usina Cresciumal (71068) | Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California | None | |
| L016101 | Lookup Table | 3.0 | Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources. | California | Zero-CI Sources (037) | Gaseous Hydrogen (HYG) | None | None | HYG037L00072019 | 10.51 | 6/28/2021 | None | Hydrogen | Cal State LA (C1063) | Cal State LA Hydrogen Research and Fueling Facility (F00145) | Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources. | None | |
| L016201 | Lookup Table | 3.0 | Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Structure E (F00376); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/29/2021 | None | Electricity | Cal State LA (C1063) | Cal State LA Structure E (F00376) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A031501 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Ipiranga Agroindustrial SA (70398); Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS229 | 43.56 | ETH018A03150100 | 49.06 | 6/30/2021 | None | Ethanol | Copersucar (3702) | Ipiranga Agroindustrial SA (70398) | Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn. | None | |
| A031701 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM237 | 45.06 | ETH018A03170100 | 51.28 | 6/30/2021 | None | Ethanol | Copersucar (3702) | Usina São José da Estiva S.A. - Açúcar e Álcool (70431) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A033301 | Tier 1 | 3.0 | Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS223 | 48.22 | ETH018A03330100 | 50.06 | 7/1/2021 | None | Ethanol | Usina São Martinho S.A. (3867) | Santa Cruz S/A Açúcar e Álcool (70484) | Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. | None | Retired |
| A033201 | Tier 1 | 3.0 | Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS219 | 46.61 | ETH018A03320100 | 50.99 | 6/30/2021 | None | Ethanol | Usina São Martinho S.A. (3867) | Usina São Martinho S.A. (71100) | Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A033701 | Tier 1 | 3.0 | Fuel Producer: JC Chemical Co., Ltd. (6094); Facility Name: JC Chemical Co., Ltd. (81585); South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional) | South Korea | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BDU238 | 20.15 | BIO001A03370100 | 24.35 | 7/9/2021 | None | Biodiesel | JC Chemical Co., Ltd. (6094) | JC Chemical Co., Ltd. (81585) | South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional) | None | |
| A034101 | Tier 1 | 3.0 | Fuel Producer: Ag Processing Inc (4552); Facility Name: AGP Methyl Ester (St Joseph) (81732); Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail | Missouri | Soybean Oil (005) | Biodiesel (BIO) | BDS213 | 50.48 | BIO005A03410100 | 54.06 | 7/9/2021 | None | Biodiesel | Ag Processing Inc (4552) | AGP Methyl Ester (St Joseph) (81732) | Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail | None | |
| A038603 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03860300 | 28.03 | 7/13/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A025201 | Tier 1 | 3.0 | Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A02520100 | 56.50 | 7/15/2021 | None | Ethanol | Companhia Alcoolquimica Nacional (C1086) | Companhia Alcoolquimica Nacional (F00194) | Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. | None | Retired |
| B019201 | Tier 2 | 3.0 | Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031B01920100 | 153.90 | 7/14/2021 | Application Package | Hydrogen | 3Degrees Group, Inc. (C1055) | Praxair - Ontario, CA (F00208) | Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California | None | |
| L016001 | Lookup Table | 3.0 | Fuel Producer: InCharge Energy Inc. (C1137); Facility Name: InCharge Energy Inc Corporate Headquarters (F00375); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 7/22/2021 | None | Electricity | InCharge Energy Inc. (C1137) | InCharge Energy Inc Corporate Headquarters (F00375) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A033501 | Tier 1 | 3.0 | Fuel Producer: COFCO International Brasil S.A. (C1110); Facility Name: Unidade POTIRENDABA (F00327); Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS212 | 46.83 | ETH018A03350100 | 52.19 | 7/28/2021 | None | Ethanol | COFCO International Brasil S.A. (C1110) | Unidade POTIRENDABA (F00327) | Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export. | None | |
| A034001 | Tier 1 | 3.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS246 | 50.16 | ETH018A03400100 | 52.45 | 7/27/2021 | None | Ethanol | BIOSEV S.A. (3869) | Usina Santa Elisa (71070) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity. | None | |
| A033801 | Tier 1 | 3.0 | Fuel Producer: BIOSEV S.A. (3869); Facility Name: Unidade MB (70568); Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS208 and ETHM228 | 47.68 and 48.63 | ETH018A03380100 | 54.03 | 7/28/2021 | None | Ethanol | BIOSEV S.A. (3869) | Unidade MB (70568) | Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity. | None | |
| A035001 | Tier 1 | 3.0 | Fuel Producer: Delek Renewables, LLC (5998); Facility Name: DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail | Mississippi | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A03500100 | 31.11 | 7/29/2021 | None | Biodiesel | Delek Renewables, LLC (5998) | DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701) | U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail | None | |
| A037401 | Tier 1 | 3.0 | Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional) | California | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | CNGLF246, CNGLF247, and CNGLF248 | 9.97, 10.32 and 13.29 | LCN025A03740100 | 18.96 | 7/29/2021 | None | Bio-CNG | HIGH MOUNTAIN FUELS LLC (4293) | Altamont Bio-LNG Plant (70526) | Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional) | None | Retired |
| A037402 | Tier 1 | 3.0 | Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional) | California | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNGLF217 and LNGLF218 | 7.39 and 7.74 | LNG025A03740200 | 15.87 | 7/29/2021 | None | Bio-LNG | HIGH MOUNTAIN FUELS LLC (4293) | Altamont Bio-LNG Plant (70526) | Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A035701 | Tier 1 | 3.0 | Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Crossett Biodiesel Plant (82217); U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail. | Arkansas | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BDT213 | 32.96 | BIO002A03570100 | 28.97 | 8/4/2021 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Crossett Biodiesel Plant (82217) | U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail. | None | |
| A039901 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A03990100 | 72.80 | 8/4/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO HARTLEY PLANT (70275) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A039902 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A03990200 | 68.94 | 8/4/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO HARTLEY PLANT (70275) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A039903 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03990300 | 26.60 | 8/4/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO HARTLEY PLANT (70275) | Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional) | None | |
| L016301 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | California | Directly Supplied Zero-CI Sources (049) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 8/2/2021 | None | Electricity | SRECTrade, Inc (C1018) | SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | None | |
| L016401 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | California | Directly Supplied Zero-CI Sources (049) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 8/5/2021 | None | Electricity | SRECTrade, Inc (C1018) | SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California. | None | |
| L016601 | Lookup Table | 3.0 | Fuel Producer: SunHarvest Partners LLC (C1147); Facility Name: SunHarvest Partners LLC (F00386); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/2/2021 | None | Electricity | SunHarvest Partners LLC (C1147) | SunHarvest Partners LLC (F00386) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L016701 | Lookup Table | 3.0 | Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: Degrees3 Transportation Solutions (F00385); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/5/2021 | None | Electricity | Degrees3 Transportation Solutions, LLC (C1111) | Degrees3 Transportation Solutions (F00385) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L016501 | Lookup Table | 3.0 | Fuel Producer: Peninsula Clean Energy (C1142); Facility Name: Peninsula Clean Energy (F00381); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/5/2021 | None | Electricity | Peninsula Clean Energy (C1142) | Peninsula Clean Energy (F00381) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A015601 | Tier 1 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Arizona | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A01560100 | 26.58 | 12/18/2019 | None | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | None | Retired |
| A039501 | Tier 1 | 3.0 | Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional) | Australia | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | None | None | BIO001A03950100 | 31.34 | 8/20/2021 | None | Biodiesel | Just Biodiesel Pty. Ltd. (C1037) | Just Biodiesel Pty. Ltd. (F00079) | Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional) | None | |
| A039502 | Tier 1 | 3.0 | Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional) | Australia | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | None | None | BIO002A03950200 | 43.33 | 8/20/2021 | None | Biodiesel | Just Biodiesel Pty. Ltd. (C1037) | Just Biodiesel Pty. Ltd. (F00079) | Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L016801 | Lookup Table | 3.0 | Fuel Producer: Disneyland Resort (C1150); Facility Name: Disneyland Resort (F00388); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/17/2021 | None | Electricity | Disneyland Resort (C1150) | Disneyland Resort (F00388) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A035301 | Tier 1 | 3.0 | Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional) | Colorado | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A03530100 | 52.36 | 8/24/2021 | None | Bio-CNG | South Platte Renew (8380) | 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641) | Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional) | None | Retired |
| A038501 | Tier 1 | 3.0 | Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional) | California | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A03850100 | 19.28 | 8/20/2021 | None | Bio-CNG | Los Angeles County Sanitation District (L375) | Biogas Conditioning System Facility (F00308) | Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional) | None | Retired |
| A025801 | Tier 1 | 3.0 | Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A02580100 | 51.59 | 9/3/2021 | None | Ethanol | Agro Industrial Tabu S.A. (C1088) | Agro Industrial Tabu (F00205) | Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. | None | Retired |
| A037201 | Tier 1 | 3.0 | Fuel Producer: USINAS ITAMARATI SA (1150); Facility Name: USINAS ITAMARATI SA (70942); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A03720100 | 58.21 | 9/17/2021 | None | Ethanol | USINAS ITAMARATI SA (1150) | USINAS ITAMARATI SA (70942) | Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker. | None | |
| L017001 | Lookup Table | 3.0 | Fuel Producer: Smart Charging Technologies (C1050) ; Facility Name: Burlington Distribution Hydrogen (F00396); Liquefied H2 produced in California from central SMR of North American fossil-based NG | California | North American Fossil NG (031) | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 9/13/2021 | None | Hydrogen | Smart Charging Technologies (C1050) | Burlington Distribution Hydrogen (F00396) | Liquefied H2 produced in California from central SMR of North American fossil-based NG | None | |
| A037901 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional) | Texas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03790100 | 23.13 | 9/28/2021 | None | Ethanol - Cellulosic | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional) | None | Retired |
| B019701 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00580100 | -167.04 | CNG026B01970100 | -177.03 | 9/28/2021 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional) | None | Retired |
| B019702 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00580200 | -151.41 | CNG026B01970200 | -156.78 | 9/28/2021 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | None | Retired |
| B019703 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00580300 | -257.78 | CNG026B01970300 | -295.26 | 9/28/2021 | Application Package | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | None | Retired |
| B017502 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Giacomini Dairy (F00305); Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B01750200 | -431.65 | 9/30/2021 | Application Package | Electricity | CleanFuture, Inc. (C1001) | Giacomini Dairy (F00305) | Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional) | None | |
| B018503 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01850300 | -382.11 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B019802 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01980200 | -414.26 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| B019804 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01980400 | -405.41 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| B019805 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01980500 | -385.40 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| A041801 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Ferrari Agroindustrial S.A. (70435); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04180100 | 51.83 | 9/30/2021 | None | Ethanol | Copersucar (3702) | Ferrari Agroindustrial S.A. (70435) | Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker | None | |
| A040202 | Tier 1 | 3.0 | Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A00340200 | 26.67 | ETH012A04020200 | 24.18 | 10/11/2021 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional) | None | |
| A037902 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional) | Texas | Corn (009) | Ethanol (ETH) | ETH009A01630100 | 64.74 | ETH009A03790200 | 63.93 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional) | None | Retired |
| B019803 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B01980300 | -420.69 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional) | None | Retired |
| A040801 | Tier 1 | 3.0 | Fuel Producer: Ag Processing Inc (4552); Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail. | Iowa | Soybean Oil (005) | Biodiesel (BIO) | BDS214 | 50.03 | BIO005A04080100 | 53.32 | 10/18/2021 | None | Biodiesel | Ag Processing Inc (4552) | Ag Processing Inc - Sgt. Bluff (81733) | Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail. | None | |
| A041201 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02480100 | 70.62 | ETH009A04120100 | 73.30 | 10/18/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Fort Dodge (70043) | Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A041202 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02480200 | 67.47 | ETH009A04120200 | 69.83 | 10/18/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Fort Dodge (70043) | Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A041203 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04120300 | 26.83 | 10/18/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Fort Dodge (70043) | Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional) | None | |
| A043001 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00690100 | 65.13 | ETH009A04300100 | 64.99 | 10/18/2021 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A043002 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04300200 | 27.97 | 10/18/2021 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | None | |
| A037801 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional) | Texas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A03780100 | 25.36 | 9/28/2021 | None | Ethanol - Cellulosic | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional) | None | Retired |
| A037802 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Corn (009) | Ethanol (ETH) | ETH009A01610100 | 64.69 | ETH009A03780200 | 66.38 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | None | Retired |
| A037804 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Corn (009) | Ethanol (ETH) | ETH009A01610400 | 72.64 | ETH009A03780400 | 73.91 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | None | Retired |
| A041301 | Tier 1 | 3.0 | Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Imperial Landfill Gas Company, LLC (F00219); Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG. | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04130100 | 53.19 | 11/23/2021 | None | Bio-CNG | TRUSTAR ENERGY LLC (6523) | Imperial Landfill Gas Company, LLC (F00219) | Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG. | None | |
| A039601 | Tier 1 | 3.0 | Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS211 (T1N-1356) | 46.32 | ETH018A03960100 | 52.79 | 11/30/2021 | None | Ethanol | Adecoagro Brasil Participacoes (4192) | Adecoagro Vale do Ivinhema Ltda. (70496) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | Retired |
| L017201 | Lookup Table | 3.0 | Fuel Producer: ChargeLab Inc. (C1153); Facility Name: ChargeLab Inc. (F00448); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/8/2021 | None | Electricity | ChargeLab Inc. (C1153) | ChargeLab Inc. (F00448) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| L017301 | Lookup Table | 3.0 | Fuel Producer: Clean Skies USA LLC (C1161); Facility Name: Clean Skies USA (F00452); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 12/3/2021 | None | Electricity | Clean Skies USA LLC (C1161) | Clean Skies USA (F00452) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California. | None | |
| A042501 | Tier 1 | 3.0 | Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. | Canada | Canola Oil (006) | Biodiesel (BIO) | BDCA202 (T1N-1406) | 51.33 | BIO006A04250100 | 47.65 | 12/16/2021 | None | Biodiesel | ADM Agri-Industries Company (6137) | ADM Agri Industries (81926) | Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. | None | Retired |
| A043301 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04330100 | 72.56 | 12/23/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO CHARLES CITY PLANT (70042) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A043302 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04330200 | 69.05 | 12/23/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO CHARLES CITY PLANT (70042) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | None | |
| A043303 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04330300 | 26.79 | 12/23/2021 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO CHARLES CITY PLANT (70042) | Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A044501 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Bonfim (70548); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM216 | 44.24 | ETH018A04450100 | 51.75 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Bonfim (70548) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A044601 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Ipaussu (71058); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM220 | 44.39 | ETH018A04460100 | 48.27 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Ipaussu (71058) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A044801 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Paraguaçu (71057); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM223 | 46.71 | ETH018A04480100 | 52.03 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Paraguaçu (71057) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A044901 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Rafard (70557); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM215R | 48.76 | ETH018A04490100 | 50.10 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Rafard (70557) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A044401 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Barra (70210); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04440100 | 53.17 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Barra (70210) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A043101 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS221R | 46.91 | ETH018A04310100 | 48.01 | 12/23/2021 | None | Ethanol | Raízen Energia S/A (3805) | Gasa (70551) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| B021801 | Tier 2 | 3.0 | Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111) ; Facility Name: Blue Mountain Biogas, LLC; Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional) | Utah | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | ELC026B02180100 | -485.51 | 1/14/2022 | Application Package | Electricity | Degrees3 Transportation Solutions, LLC (C1111) | Blue Mountain Biogas, LLC | Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional) | None | |
| B024102 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | California | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B02410200 | 58.16 | 12/28/2021 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | None | |
| B024201 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California. | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B02420100 | -293.72 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California. | None | |
| B024202 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California. | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B02420200 | -259.22 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California. | None | |
| B024203 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | None | None | HYG025B02420300 | 74.70 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California | None | |
| B024204 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California | California | h American Fossil NG ( | Gaseous Hydrogen (HYG) | None | None | HYG031B02420400 | 115.15 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B024205 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California. | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B02420500 | -254.95 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California. | None | |
| B024206 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B02420600 | -239.31 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California | None | |
| B024207 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B02420700 | -220.45 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California | None | |
| B024208 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B02420800 | -204.81 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California | None | |
| B024209 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B02420900 | 109.81 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California | None | |
| B024210 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B02421000 | 125.44 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California | None | |
| B024211 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California | California | h American Fossil NG ( | Liquid Hydrogen (HYL) | None | None | HYL031B02421100 | 169.55 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California | None | |
| B024212 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California | California | h American Fossil NG ( | Liquid Hydrogen (HYL) | None | None | HYL031B02421200 | 153.91 | 12/28/2021 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California | None | |
| A043601 | Tier 1 | 3.0 | Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04360100 | 71.53 | 2/1/2022 | None | Ethanol | AL CORN CLEAN FUEL, LLC (4825) | AL CORN CLEAN FUEL, LLC (70087) | Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A044701 | Tier 1 | 3.0 | Fuel Producer: Raízen Energia S/A (3805); Facility Name: Junqueira (70553); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHM217 | 47.82 | ETH018A04470100 | 55.75 | 1/5/2022 | None | Ethanol | Raízen Energia S/A (3805) | Junqueira (70553) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A039701 | Tier 1 | 3.0 | Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. | North Dakota | Canola Oil (006) | Biodiesel (BIO) | BDCA203 (T1N-1457) | 52.25 | BIO006A03970100 | 47.44 | 12/20/2021 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Velva (82790) | Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. | None | Retired |
| A040701 | Tier 1 | 3.0 | Fuel Producer: Guarani SA (3833); Facility Name: Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04070100 | 47.51 | 2/4/2022 | None | Ethanol | Guarani SA (3833) | Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A041701 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial Barra Grande (70412); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | ETHS250 | 47.71 | ETH018A04170100 | 52.85 | 2/4/2022 | None | Ethanol | Copersucar (3702) | Açucareira Quatá S/A – Filial Barra Grande (70412) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A042001 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial São José (70432); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04200100 | 49.11 | 2/22/2022 | None | Ethanol | Copersucar (3702) | Açucareira Quatá S/A – Filial São José (70432) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| A045001 | Tier 1 | 3.0 | Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional) | Pennsylvania | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A04500100 | 58.09 | 2/22/2022 | None | Biodiesel | WORLD ENERGY HARRISBURG LLC (6425) | WORLD ENERGY HARRISBURG LLC (81499) | Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional) | None | Retired |
| A045002 | Tier 1 | 3.0 | Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional) | Pennsylvania | oking Oil/Waste Oil (UC | Biodiesel (BIO) | None | None | BIO001A04500200 | 21.59 | 2/22/2022 | None | Biodiesel | WORLD ENERGY HARRISBURG LLC (6425) | WORLD ENERGY HARRISBURG LLC (81499) | US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional) | None | Retired |
| A044001 | Tier 1 | 3.0 | Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional) | Kansas | Corn (009) | Ethanol (ETH) | None | None | ETH009A04400100 | 72.37 | 3/2/2022 | None | Ethanol | Element, LLC (C1020) | Element (F00048) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional) | None | Retired |
| A044002 | Tier 1 | 3.0 | Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional) | Kansas | Corn (009) | Ethanol (ETH) | None | None | ETH009A04400200 | 62.07 | 3/2/2022 | None | Ethanol | Element, LLC (C1020) | Element (F00048) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional) | None | Retired |
| L017401 | Lookup Table | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Compressed H2 produced in California from central SMR of North American fossil-based NG | California | h American Fossil NG ( | Gaseous Hydrogen (HYG) | None | None | HYG031L00072019 | 117.67 | 2/25/2022 | None | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Compressed H2 produced in California from central SMR of North American fossil-based NG | None | |
| A041901 | Tier 1 | 3.0 | Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04190100 | 53.36 | 3/21/2022 | None | Ethanol | Copersucar (3702) | Açucareira Quatá S.A. (70406) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| B026804 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B01000100 | 23.93 | AJF002B02680400 | 19.54 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |
| B026805 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B01000200 | 23.93 | RND002B02680500 | 19.54 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026806 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B01000300 | 23.93 | RNT002B02680600 | 19.54 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B026807 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B01190100 | 19.51 | AJF002B02680700 | 15.64 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B026808 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B01190200 | 19.51 | RND002B02680800 | 15.64 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026809 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B01190300 | 19.51 | RNT002B02680900 | 15.64 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B026813 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B00430100 | 37.13 | AJF002B02681300 | 32.93 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |
| B026814 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B00430200 | 37.13 | RND002B02681400 | 32.93 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026815 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B00430300 | 37.13 | RNT002B02681500 | 32.93 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B026816 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B00440100 | 42.91 | AJF002B02681600 | 38.43 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | None | Retired |
| B026817 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B00440200 | 42.91 | RND002B02681700 | 38.43 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | None | Retired |
| B026818 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B00440300 | 42.91 | RNT002B02681800 | 38.43 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | None | Retired |
| B021501 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02150100 | -310.71 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | None | Retired |
| B021502 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | None | None | LNG026B02150200 | -296.99 | 3/30/2022 | Application Package | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional) | None | Retired |
| B021503 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN026B02150300 | -293.45 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional) | None | Retired |
| A044201 | Tier 1 | 3.0 | Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04420100 | 72.16 | 3/29/2022 | None | Ethanol | Lincolnway Energy, LLC (4830) | Lincolnway Energy (70092) | Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A044203 | Tier 1 | 3.0 | Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04420300 | 24.70 | 3/29/2022 | None | Ethanol - Cellulosic | Lincolnway Energy, LLC (4830) | Lincolnway Energy (70092) | Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional) | None | Retired |
| B026703 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02850100 | 12.91 | BIO001B02670300 | 15.71 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | None | Retired |
| B026704 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02850400 | 15.81 | BIO001B02670400 | 16.34 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | None | Retired |
| B026705 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02850300 | 17.86 | BIO001B02670500 | 20.86 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | None | Retired |
| B028003 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California. | California | Vastewater Sludge (030 | Liquid Hydrogen (HYL) | None | None | HYL030B02800300 | 109.01 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California. | None | |
| B028004 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California. | California | Vastewater Sludge (030 | Gaseous Hydrogen (HYG) | None | None | HYG030B02800400 | 76.98 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California. | None | |
| B028005 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California. | California | Swine Manure (044) | Liquid Hydrogen (HYL) | None | None | HYL044B02800500 | -338.45 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California. | None | |
| B028006 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California. | California | Swine Manure (044) | Liquid Hydrogen (HYL) | None | None | HYL044B02800600 | -354.78 | 3/29/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California. | None | |
| A043701 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional) | Oklahoma | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04370100 | 37.00 | 4/11/2022 | None | Bio-CNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional) | None | Retired |
| A043702 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Oklahoma | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A04370200 | 50.61 | 4/11/2022 | None | Bio-LNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | Retired |
| A043703 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Oklahoma | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A04370300 | 53.70 | 4/11/2022 | None | Bio-CNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | Retired |
| A045201 | Tier 1 | 3.0 | Fuel Producer: VALE DO PARANA S.A ALCOOL E ACUCAR (6079); Facility Name: VALE DO PARANA S.A ALCOOL E ACUCAR (71119); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04520100 | 50.69 | 4/11/2022 | None | Ethanol | VALE DO PARANA S.A ALCOOL E ACUCAR (6079) | VALE DO PARANA S.A ALCOOL E ACUCAR (71119) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A045601 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | California | Distillers' Corn Oil (003 | Biodiesel | BIO003A03760100 | 32.12 | BIO003A04560100 | 30.15 | 4/7/2022 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL (80341) | California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | None | Retired |
| A045602 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel | None | None | BIO001A04560200 | 23.48 | 4/7/2022 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL (80341) | North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | None | Retired |
| A045603 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL ( 80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | California | (animal and poultry fat | Biodiesel (BIO) | None | None | BIO002A04560300 | 36.09 | 4/7/2022 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL ( 80341) | North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional) | None | Retired |
| A045801 | Tier 1 | 3.0 | Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | None | None | BIO001A04580100 | 14.69 | 5/10/2022 | None | Biodiesel | New Leaf Biofuel (7768) | New Leaf Biofuel (83541) | California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional) | None | Retired |
| A045802 | Tier 1 | 3.0 | Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional) | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | None | None | BIO001A04580200 | 20.58 | 5/10/2022 | None | Biodiesel | New Leaf Biofuel (7768) | New Leaf Biofuel (83541) | California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional) | None | Retired |
| B030201 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | Minnesota | Distillers' Corn Oil (003 | Biodiesel (BIO) | BIO003A00830300 | 24.55 | BIO003B03020100 | 24.50 | 6/3/2022 | Application Package | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | None | Retired |
| B030202 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | Minnesota | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A00830400 | 17.72 | BIO001B03020200 | 18.50 | 6/3/2022 | Application Package | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | None | Retired |
| B030203 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | Minnesota | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A00830500 | 11.99 | BIO001B03020300 | 12.50 | 6/3/2022 | Application Package | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional) | None | Retired |
| B030204 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional) | Minnesota | (animal and poultry fat | Biodiesel (BIO) | BIO002A00830600 | 28.89 | BIO002B03020400 | 29.00 | 6/3/2022 | Application Package | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional) | None | Retired |
| A046101 | Tier 1 | 3.0 | Fuel Producer: GARLAND RENEWABLES, LLC (1639); Facility Name: GARLAND RENEWABLES, LLC (71921; Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04610100 | 32.52 | 5/13/2022 | None | Bio-CNG | GARLAND RENEWABLES, LLC (1639) | GARLAND RENEWABLES, LLC (71921 | Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional) | None | |
| A046601 | Tier 1 | 3.0 | Fuel Producer: INNOLTEK (C1126); Facility Name: INNOLTEK (F00340); Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail. | Canada | (animal and poultry fat | Biodiesel (BIO) | None | None | BIO002A04660100 | 34.76 | 6/13/2022 | None | Biodiesel | INNOLTEK (C1126) | INNOLTEK (F00340) | Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail. | None | |
| A040601 | Tier 1 | 3.0 | Fuel Producer: EDINBURG RENEWABLES, LLC (6401); Facility Name: CITY OF EDINBURG LANDFILL (71223); Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG. | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04060100 | 37.12 | 12/31/2021 | None | Bio-CNG | EDINBURG RENEWABLES, LLC (6401) | CITY OF EDINBURG LANDFILL (71223) | Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B025001 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02500100 | -182.67 | 6/28/2022 | Application Package | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | None | Retired |
| B025002 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02500200 | -267.51 | 6/28/2022 | Application Package | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | None | Retired |
| B025003 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02500300 | -255.34 | 6/28/2022 | Application Package | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030701 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03070100 | -353.38 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030702 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03070200 | -405.57 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030703 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03070300 | -255.83 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030705 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03070500 | -366.91 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030704 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03070400 | -249.43 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | None | Retired |
| B032901 | Tier 2 | 3.0 | Fuel Producer: Messer LLC (f.k.a. Linde LLC) (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations. | California | h American Fossil NG ( | Liquid Hydrogen (HYL) | None | None | HYL031B03290100 | 153.28 | 6/23/2022 | Application Package | Hydrogen | Messer LLC (f.k.a. Linde LLC) (L012) | Linde Praxair (F00477) | Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations. | None | |
| A044101 | Tier 1 | 3.0 | Fuel Producer: GREENAMERICA BIOFUELS ORD LLC (1481); Facility Name: GREEN PLAINS ORD, LLC (71641); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI. | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A04410100 | 70.65 | 6/29/2022 | None | Ethanol | GREENAMERICA BIOFUELS ORD LLC (1481) | GREEN PLAINS ORD, LLC (71641) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI. | None | |
| B028301 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02830100 | -195.09 | 6/29/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | DEER RUN RNG PROJECT (71482) | Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | Retired |
| B030801 | Tier 2 | 3.0 | Fuel Producer: WOF SW GGP 1 LLC (W009); Facility Name: Green Gas Partners Stanfield (F00003); Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional) | Arizona | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03080100 | -362.84 | 6/30/2022 | Application Package | Bio-CNG | WOF SW GGP 1 LLC (W009) | Green Gas Partners Stanfield (F00003) | Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B031001 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100100 | -349.17 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031002 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100200 | -210.67 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031004 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100400 | -417.26 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031003 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100300 | -406.28 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031005 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100500 | -417.24 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031006 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03100600 | -356.29 | 6/28/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| A046201 | Tier 1 | 3.0 | Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04620101 | 33.08 | 6/23/2022 | None | Ethanol | CORN, LP (5065) | CORN, LP (70145) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A046202 | Tier 1 | 3.0 | Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00330101 | 71.09 | ETH009A04620201 | 70.62 | 6/23/2022 | None | Ethanol | CORN, LP (5065) | CORN, LP (70145) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional) | None | Retired |
| L018801 | Lookup Table | 3.0 | Fuel Producer: Silicon Valley Clean Energy (C1183); Facility Name: Silicon Valley Clean Energy Authority (F00484); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/14/2022 | None | Electricity | Silicon Valley Clean Energy (C1183) | Silicon Valley Clean Energy Authority (F00484) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019101 | Lookup Table | 3.0 | Fuel Producer: Southern California Edison (C1185); Facility Name: Southern California Edison (F00489); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/28/2022 | None | Electricity | Southern California Edison (C1185) | Southern California Edison (F00489) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019301 | Lookup Table | 3.0 | Fuel Producer: Skyview Finance Company 2, LLC (C1174); Facility Name: Skyview Finance Company 2, LLC ZCI CA B&C (F00492); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 3/28/2022 | None | Electricity | Skyview Finance Company 2, LLC (C1174) | Skyview Finance Company 2, LLC ZCI CA B&C (F00492) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019401 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Supplied Zero-CI Sourc | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 4/8/2022 | None | Electricity | SRECTrade, Inc (C1018) | SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| L019601 | Lookup Table | 3.0 | Fuel Producer: Redwood City School District (C1205); Facility Name: Redwood City School District (F00524); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/22/2022 | None | Electricity | Redwood City School District (C1205) | Redwood City School District (F00524) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019701 | Lookup Table | 3.0 | Fuel Producer: The Mobility House (C1200); Facility Name: The Mobility House (F00525); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/24/2022 | None | Electricity | The Mobility House (C1200) | The Mobility House (F00525) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019801 | Lookup Table | 3.0 | Fuel Producer: 7-Eleven, Inc. (C1204); Facility Name: 7-Eleven, Inc. (F00526); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 6/24/2022 | None | Electricity | 7-Eleven, Inc. (C1204) | 7-Eleven, Inc. (F00526) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A041001 | Tier 1 | 3.0 | Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04100100 | 52.77 | 7/18/2022 | None | Ethanol | JAPUNGU AGROINDUSTRIAL LTDA (C1145) | Japungu Agroindustrial Ltda (F00383) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | Retired |
| A045701 | Tier 1 | 3.0 | Fuel Producer: BP Biofuels (4427); Facility Name: Tropical Bioenergia SA (71078); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A04570100 | 50.57 | 7/18/2022 | None | Ethanol | BP Biofuels (4427) | Tropical Bioenergia SA (71078) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | None | |
| L019001 | Lookup Table | 3.0 | Fuel Producer: San Francisco Bay Area Rapid Transit District (BART) (C1176); Facility Name: SF BART (F00482); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.0 | 3/17/2022 | None | Electricity | San Francisco Bay Area Rapid Transit District (BART) (C1176) | SF BART (F00482) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A046702 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A04670200 | 73.37 | 7/18/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO LINDEN PLANT (70196) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | None | |
| A046701 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04670100 | 27.73 | 7/18/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO LINDEN PLANT (70196) | Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | None | |
| A046703 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | None | None | ETH009A04670300 | 70.15 | 7/18/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO LINDEN PLANT (70196) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional) | None | |
| L020201 | Lookup Table | 3.0 | Fuel Producer: County of Santa Clara (C1208); Facility Name: County of Santa Clara (F00530); Zero-CI electricity from solar PV generated in CA | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 7/11/2022 | None | Electricity | County of Santa Clara (C1208) | County of Santa Clara (F00530) | Zero-CI electricity from solar PV generated in CA | None | |
| L020301 | Lookup Table | 3.0 | Fuel Producer: City of Palo Alto Utilities (P600); Facility Name: City of Palo Alto Utilities (F00499); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 7/13/2022 | None | Electricity | City of Palo Alto Utilities (P600) | City of Palo Alto Utilities (F00499) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A046801 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04680100 | 26.52 | 7/20/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO WELCOME PLANT (70276) | Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A046802 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04680200 | 72.15 | 7/20/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO WELCOME PLANT (70276) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | None | |
| A046803 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04680300 | 68.59 | 7/20/2022 | None | Ethanol | Valero Renewable Fuels (3201) | VALERO WELCOME PLANT (70276) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional) | None | |
| A046902 | Tier 1 | 3.0 | Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional) | Wisconsin | Corn (009) | Ethanol (ETH) | None | None | ETH009A04690200 | 69.34 | 9/19/2022 | None | Ethanol | BADGER STATE ETHANOL LLC (4469) | Badger State Ethanol (70130) | Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional) | None | |
| A046903 | Tier 1 | 3.0 | Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional) | Wisconsin | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04690300 | 27.41 | 9/19/2022 | None | Ethanol | BADGER STATE ETHANOL LLC (4469) | Badger State Ethanol (70130) | Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional) | None | |
| A046901 | Tier 1 | 3.0 | Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional) | Wisconsin | Corn (009) | Ethanol (ETH) | None | None | ETH009A04690100 | 74.18 | 9/19/2022 | None | Ethanol | BADGER STATE ETHANOL LLC (4469) | Badger State Ethanol (70130) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional) | None | |
| L020601 | Lookup Table | 3.0 | Fuel Producer: STX Commodities LLC (C1195) ; Facility Name: STX Commodities LLC 2.0 (F00539); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity | None | None | ELC037L00072019 | 0.00 | 9/14/2022 | None | Electricity | STX Commodities LLC (C1195) | STX Commodities LLC 2.0 (F00539) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| B028201 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B02820100 | -272.08 | 9/23/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | U.S. GAIN RNG FACILITY S&S (71361) | Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | Retired |
| B032301 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | California | Distillers' Corn Oil (003 | Renewable Diesel (RND) | None | None | RND003B03230100 | 25.46 | 9/20/2022 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | None | |
| B033801 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional) | Texas | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B03380100 | -417.96 | 9/23/2022 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | DALHART RNG, LLC (70981) | Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031101 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110101 | -418.04 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031102 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110200 | -383.14 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031103 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110300 | -419.34 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B031105 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110500 | -276.38 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031104 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110400 | -299.39 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031107 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110700 | -341.84 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031106 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110600 | -403.86 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031108 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03110800 | -273.88 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | None | Retired |
| B031501 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03150100 | -403.96 | 9/29/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional) | None | Retired |
| B034601 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03460100 | -311.72 | 9/28/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET LAMB RNG PROJECT (71101) | Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional) | None | Retired |
| B034801 | Tier 2 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Air Products and Chemicals SMR Wilmington (F00384); Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03480100 | -147.20 | 9/29/2022 | Application Package | Hydrogen | Shell Energy North America (6154) | Air Products and Chemicals SMR Wilmington (F00384) | Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional) | None | |
| B034901 | Tier 2 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03490100 | -151.76 | 9/29/2022 | Application Package | Hydrogen | Shell Energy North America (6154) | Carson Hydrogen Plant (F00059) | Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional) | None | |
| B035001 | Tier 2 | 3.0 | Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03500100 | -89.98 | 9/29/2022 | Application Package | Hydrogen | Shell Energy North America (6154) | Sacramento Hydrogen Plant (F00102) | L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional) | None | Retired |
| B035301 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03530100 | -344.72 | 9/29/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | U.S. GAIN RNG FACILITY DALLMAN (71341) | Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional) | None | Retired |
| B036001 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03600100 | -159.04 | 9/27/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B036003 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03600300 | -104.64 | 9/27/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional) | None | Retired |
| B036002 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03600200 | -120.27 | 9/27/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional) | None | Retired |
| B037301 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03730100 | -107.85 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional) | None | |
| B037302 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03730200 | -192.70 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional) | None | Retired |
| B037303 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03730300 | -146.62 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional) | None | |
| B037304 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03730400 | -231.46 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional) | None | Retired |
| B037305 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03730500 | -92.22 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional) | None | |
| B037306 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03730600 | -177.06 | 9/29/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional) | None | Retired |
| L020701 | Lookup Table | 3.0 | Fuel Producer: Apple (A449); Facility Name: VP02 (V8866); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/28/2022 | None | Electricity | Apple (A449) | VP02 (V8866) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L020901 | Lookup Table | 3.0 | Fuel Producer: Revolv Global Inc. (C1210); Facility Name: Revolv Global Inc. (F00553); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/28/2022 | None | Electricity | Revolv Global Inc. (C1210) | Revolv Global Inc. (F00553) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| A048401 | Tier 1 | 3.0 | Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04840100 | 72.78 | 10/12/2022 | None | Ethanol | Heartland Corn Products (4827) | Heartland Corn Products (70089) | Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | None | |
| A048402 | Tier 1 | 3.0 | Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04840200 | 26.07 | 10/12/2022 | None | Ethanol - Cellulosic | Heartland Corn Products (4827) | Heartland Corn Products (70089) | Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A048901 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A04890100 | 74.58 | 10/12/2022 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Albion (70283) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional) | None | |
| A048902 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A04890200 | 70.52 | 10/12/2022 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Albion (70283) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional) | None | |
| A048903 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04890300 | 27.18 | 10/12/2022 | None | Ethanol - Cellulosic | Valero Renewable Fuels (3201) | Valero Renewable Fuels Albion (70283) | Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional) | None | |
| A049001 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04900100 | 71.51 | 10/12/2022 | None | Ethanol | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A049002 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04900200 | 61.15 | 10/12/2022 | None | Ethanol | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional) | None | Retired |
| A049003 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04900300 | 22.33 | 10/12/2022 | None | Ethanol - Cellulosic | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional) | None | Retired |
| A049401 | Tier 1 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Tres Rios Water Reclamation Facility (F00443); Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional) | Arizona | Vastewater Sludge (030 | Compressed Natural Gas (CNG) | None | None | CNG030A04940100 | 27.41 | 10/10/2022 | None | Bio-CNG | BLUE SOURCE LLC (6086) | Tres Rios Water Reclamation Facility (F00443) | Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional) | None | |
| A047101 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A04710101 | 73.70 | 11/8/2022 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional) | None | |
| A047102 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A04710201 | 64.99 | 11/8/2022 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional) | None | |
| A047103 | Tier 1 | 3.0 | Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04710301 | 27.35 | 11/8/2022 | None | Ethanol | Trenton Agri Products, LLC (4754) | Trenton Agri Products, LLC (70053) | Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional) | None | |
| B032501 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | California | Soybean Oil (005) | Renewable Gasoline (RNG) | None | None | RNG005B03250100 | 63.35 | 12/20/2022 | Application Package | Renewable Gasoline | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | None | |
| B032502 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | California | Soybean Oil (005) | Renewable Gasoline (RNG) | None | None | RNG005B03250200 | 60.38 | 12/20/2022 | Application Package | Renewable Gasoline | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B032503 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | California | Canola Oil (006) | Renewable Gasoline (RNG) | None | None | RNG006B03250300 | 58.48 | 12/20/2022 | Application Package | Renewable Gasoline | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional) | None | |
| B033701 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | California | Distillers' Corn Oil (003 | Renewable Gasoline (RNG) | None | None | RNG003B03370100 | 30.86 | 12/20/2022 | Application Package | Renewable Gasoline | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional) | None | |
| B035201 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03520100 | -411.77 | 12/5/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional) | None | Retired |
| B035202 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03520200 | -351.51 | 12/5/2022 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional) | None | Retired |
| A048601 | Tier 1 | 3.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker. | South Korea | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A01050100 | 27.89 | BIO001A04860100 | 25.98 | 12/19/2022 | None | Biodiesel | Dansuk Industrial Co., Ltd (5953) | Dansuk Industrial Co., Ltd (81302) | South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker. | None | |
| A048602 | Tier 1 | 3.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker. | South Korea | (animal and poultry fat | Biodiesel (BIO) | None | None | BIO002A04860200 | 37.80 | 12/19/2022 | None | Biodiesel | Dansuk Industrial Co., Ltd (5953) | Dansuk Industrial Co., Ltd (81302) | South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker. | None | |
| B036601 | Tier 2 | 3.0 | Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional) | Utah | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02140100 | -413.67 | CNG044B03660100 | -414.59 | 12/7/2022 | Application Package | Bio-CNG | Element Markets Renewable Energy, LLC (5877) | MILFORD FARM (71483) | Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional) | None | Retired |
| B037801 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California. | California | Landfill Gas (025) | Liquid Hydrogen (HYL) | None | None | HYL025B03780100 | 107.19 | 12/19/2022 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California. | None | |
| B038501 | Tier 2 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03850100 | -180.73 | 12/21/2022 | Application Package | Bio-CNG | BLUE SOURCE LLC (6086) | Green Valley Dairy LLC (F00198) | Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | Retired |
| B039101 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California. | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03910100 | -197.27 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California. | None | |
| B039102 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03910200 | -236.03 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | None | |
| B039103 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen. | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03910300 | -181.64 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394)Verification Body Name: | Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B039201 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California. | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03920100 | -269.91 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California. | None | |
| B039202 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B03920200 | -308.67 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | None | |
| B039203 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen. | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B03920300 | -254.28 | 12/22/2022 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in | None | |
| B034501 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03450100 | -318.35 | 12/27/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET LAKESHORE RNG PROJECT (71321) | Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | Retired |
| B034701 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET BOXLER RNG PROJECT (71222); Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03470100 | -206.88 | 12/27/2022 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET BOXLER RNG PROJECT (71222) | Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | |
| A048101 | Tier 1 | 3.0 | Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: USINA OUROESTE AÇÚCAR E ALCOOL (F00509); Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH019A04810100 | 49.73 | 12/27/2022 | None | Ethanol | BP Bunge Bioenergia SA (C1196) | USINA OUROESTE AÇÚCAR E ALCOOL (F00509) | Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker. | None | |
| A048301 | Tier 1 | 3.0 | Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: AGROINDUSTRIAL SANTA JULIANA (F00507); Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker. | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH019A04830100 | 51.34 | 12/27/2022 | None | Ethanol | BP Bunge Bioenergia SA (C1196) | AGROINDUSTRIAL SANTA JULIANA (F00507) | Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker. | None | |
| B037001 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B03700100 | -408.25 | 12/28/2022 | Application Package | Bio-CNG | Anew RNG, LLC (5877) | GREEN HILLS FARM (71881) | Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional) | None | Retired |
| B037101 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | None | None | CNG044B03710100 | -412.77 | 12/28/2022 | Application Package | Bio-CNG | Anew RNG, LLC (5877) | WHITETAIL FARM (71882) | Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional) | None | Retired |
| L018901 | Lookup Table | 3.0 | Fuel Producer: 4GEN LOGISTICS, L.L.C. (C1156); Facility Name: 4GEN Fastlane (F00432); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 00.00 | 3/25/2022 | None | Electricity | 4GEN LOGISTICS, L.L.C. (C1156) | 4GEN Fastlane (F00432) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L019201 | Lookup Table | 3.0 | Fuel Producer: Linde LLC (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck. | California | h American Fossil NG ( | Liquid Hydrogen (HYL) | None | None | HYL031L00072019 | 150.94 | 6/30/2022 | None | Hydrogen | Linde LLC (L012) | Linde Praxair (F00477) | Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck. | None | |
| L020501 | Lookup Table | 3.0 | Fuel Producer: Total Warehouse Inc. (C1214); Facility Name: Total Warehouse Inc. (F00541); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity | None | None | ELC037L00072019 | 00.00 | 9/16/2022 | None | Electricity | Total Warehouse Inc. (C1214) | Total Warehouse Inc. (F00541) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A010501 | Tier 1 | 3.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker | South Korea | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A01050100 | 27.89 | BIO001A01050101 | 25.00 | 12/17/2019 | None | Biodiesel | Dansuk Industrial Co., Ltd (5953) | Pyeongtaek 2 (80202) | South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker | None | Retired |
| A012903 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A01290300 | 27.44 | ETH012A01290301 | 27.01 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A013003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01300300 | 27.54 | ETH012A01300301 | 25.09 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A014603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | Michigan | Corn Fiber (012) | Ethanol (ETH) | ETH012A01460300 | 27.33 | ETH012A01460301 | 27.03 | 9/24/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01500300 | 27.72 | ETH012A01500301 | 27.19 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015103 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01510300 | 27.69 | ETH012A01510301 | 26.17 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064 | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108 | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A01520300 | 27.00 | ETH012A01520301 | 25.89 | 10/3/2019 | None | Ethanol - Cellulosic | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A019802 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A01980200 | 23.46 | ETH012A01980201 | 23.04 | 6/24/2020 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A020904 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A02090400 | 27.48 | ETH012A02090401 | 25.14 | 6/24/2020 | None | Ethanol - Cellulosic | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | |
| A021203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California | Missouri | Corn Fiber (012) | Ethanol (ETH) | ETH012A02120300 | 26.19 | ETH012A02120301 | 25.32 | 4/28/2020 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A021703 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | North Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A02170300 | 25.72 | ETH012A02170301 | 24.41 | 7/27/2020 | None | Ethanol - Cellulosic | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| A022404 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A02240400 | 23.96 | ETH012A02240402 | 26.00 | 6/24/2020 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024503 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A02450300 | 22.56 | ETH012A02450303 | 24.71 | 12/4/2020 | None | Ethanol - Cellulosic | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A024603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A02460300 | 29.41 | ETH012A02460302 | 28.47 | 12/29/2020 | None | Ethanol - Cellulosic | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A027202 | Tier 1 | 3.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A02720200 | 26.60 | ETH012A02720201 | 26.40 | 10/21/2020 | None | Ethanol - Cellulosic | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | |
| A030901 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A03090100 | 24.46 | ETH012A03090101 | 24.84 | 5/4/2021 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| B017403 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California. | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012B01740300 | 29.14 | ETH012B01740301 | 29.48 | 9/24/2021 | Application Package | Ethanol - Cellulosic | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| B019001 | Tier 2 | 3.0 | Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | Kansas | Distillers' Corn Oil (003 | Renewable Diesel (RND) | RND003B01900100 | 46.31 | RND003B01900101 | 56.37 | 6/25/2021 | Application Package | Renewable Diesel | East Kansas Agri-Energy, LLC (4483) | East Kansas Agri-Energy, LLC (83483) | Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional) | 2021 AFPR Recert Complete | |
| B019002 | Tier 2 | 3.0 | Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail | Kansas | Distillers' Corn Oil (003 | Renewable Naphtha (RNT) | RNT003B01900200 | 46.31 | RNT003B01900201 | 56.37 | 6/25/2021 | Application Package | Renewable Naphtha | East Kansas Agri-Energy, LLC (4483) | East Kansas Agri-Energy, LLC (83483) | Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail | 2021 AFPR Recert Complete | |
| A039402 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A03940200 | 27.87 | ETH012A03940201 | 27.95 | 10/14/2021 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A042302 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A04230200 | 24.02 | ETH012A04230201 | 24.42 | 10/26/2021 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B024103 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline | California | Canola Oil (006) | Renewable Diesel (RND) | RND006B02410300 | 51.87 | RND006B02410301 | 52.90 | 12/28/2021 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline | 2021 AFPR Recert Complete | |
| B024101 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline | California | Soybean Oil (005) | Renewable Diesel (RND) | RND005B02410100 | 54.68 | RND005B02410101 | 55.39 | 12/28/2021 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline | 2021 AFPR Recert Complete | |
| A043602 | Tier 1 | 3.0 | Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A04360200 | 24.89 | ETH012A04360201 | 25.15 | 2/1/2022 | None | Ethanol | AL CORN CLEAN FUEL, LLC (4825) | AL CORN CLEAN FUEL, LLC (70087) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A037903 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03790300 | 64.00 | ETH010A03790301 | 65.92 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | Retired |
| A049301 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional) | Iowa | Corn (009) | | ETH009A02540100 | 69.55 | ETH009A04930100 | 73.97 | 1/23/2023 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Albert City (70142) | Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional) | None | |
| A049302 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02540200 | 66.07 | ETH009A04930200 | 70.72 | 1/23/2023 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Albert City (70142) | Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional) | None | |
| A049303 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04930300 | 27.65 | 1/23/2023 | None | Ethanol - Cellulosic | Valero Renewable Fuels (3201) | Valero Renewable Fuels LLC - Albert City (70142) | Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional) | None | |
| A008601 | Tier 1 | 3.0 | Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00860100 | 62.37 | ETH009A00860101 | 63.00 | 4/16/2019 | None | Ethanol | Bridgeport Ethanol, LLC 5934 | Bridgeport Ethanol, LLC 70217 | Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A021201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California | Missouri | Corn (009) | Ethanol (ETH) | ETH009A02120100 | 75.09 | ETH009A02120102 | 75.47 | 4/28/2020 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A031201 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | California | Soybean Oil (005) | Biodiesel (BIO) | BIO005A03120100 | 57.16 | BIO005A03120101 | 63.92 | 3/23/2021 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | 2021 AFPR Recert Complete | Retired |
| A031202 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | California | Canola Oil (006) | Biodiesel (BIO) | BIO006A03120200 | 51.65 | BIO006A03120201 | 59.19 | 3/23/2021 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | 2021 AFPR Recert Complete | Retired |
| A031204 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. | California | (animal and poultry fat | Biodiesel (BIO) | BIO002A03120400 | 31.28 | BIO002A03120401 | 38.49 | 3/23/2021 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. | 2021 AFPR Recert Complete | Retired |
| A031205 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | California | (animal and poultry fat | Biodiesel (BIO) | BIO002A03120500 | 32.45 | BIO002A03120501 | 39.35 | 3/23/2021 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | 2021 AFPR Recert Complete | Retired |
| A031206 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A03120600 | 21.27 | BIO001A03120601 | 26.60 | 3/23/2021 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | 2021 AFPR Recert Complete | Retired |
| A034801 | Tier 1 | 3.0 | Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional) | Texas | (animal and poultry fat | Biodiesel (BIO) | BIO002A03480100 | 30.80 | BIO002A03480101 | 31.95 | 7/28/2021 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A042602 | Tier 1 | 3.0 | Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. | Iowa | Soybean Oil (005) | Biodiesel (BIO) | BIO005A04260200 | 55.05 | BIO005A04260201 | 54.75 | 12/22/2021 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. | 2021 AFPR Recert Complete | |
| A042601 | Tier 1 | 3.0 | Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. | Iowa | (animal and poultry fat | Biodiesel (BIO) | BIO002A04260100 | 29.23 | BIO002A04260101 | 29.39 | 12/22/2021 | None | Biodiesel | Western Iowa Energy (4670) | Western Iowa Energy (82630) | Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. | 2021 AFPR Recert Complete | |
| A043901 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A04390100 | 53.17 | 2/22/2022 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Skyline RNG Facility (F00217) | Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional) | None | |
| A043902 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Texas | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A04390200 | 68.92 | 2/22/2022 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Skyline RNG Facility (F00217) | Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional) | None | |
| A043903 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Texas | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LCN025A04390300 | 72.00 | 2/22/2022 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Skyline RNG Facility (F00217) | Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | None | |
| B026701 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | Distillers' Corn Oil (003 | Biodiesel (BIO) | BIO003B02670100 | 28.67 | BIO003B02670101 | 28.80 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2021 AFPR Recert Complete | Retired |
| B026702 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | California | (animal and poultry fat | Biodiesel (BIO) | BIO002B02670200 | 32.53 | BIO002B02670201 | 32.73 | 3/29/2022 | Application Package | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A012001 | Tier 1 | 3.0 | Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01200101 | 65.30 | ETH009A01200102 | 64.69 | 9/5/2019 | None | Ethanol | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | |
| A012901 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01290100 | 74.62 | ETH009A01290101 | 73.48 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A012902 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01290200 | 67.54 | ETH009A01290201 | 66.73 | 9/24/2019 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A013001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01300100 | 74.35 | ETH009A01300101 | 72.10 | 9/24/2019 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A049101 | Tier 1 | 3.0 | Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California | Washington | Canola Oil (006) | Biodiesel (BIO) | BDCA204 | 52.87 | BIO006A04910100 | 49.00 | 2/13/2023 | None | Biodiesel | REG Grays Harbor, LLC (6326) | REG Grays Harbor, LLC (82954) | North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A049102 | Tier 1 | 3.0 | Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California | Washington | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A04910200 | 55.00 | 2/13/2023 | None | Biodiesel | REG Grays Harbor, LLC (6326) | REG Grays Harbor, LLC (82954) | North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California | None | |
| A049501 | Tier 1 | 3.0 | Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04950100 | 73.15 | 2/14/2023 | None | Ethanol | RING-NECK ENERGY & FEED, LLC (6274) | RING-NECK ENERGY & FEED, LLC (70361) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional) | None | |
| A049502 | Tier 1 | 3.0 | Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274) ; Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A04950200 | 65.12 | 2/14/2023 | None | Ethanol | RING-NECK ENERGY & FEED, LLC (6274) | RING-NECK ENERGY & FEED, LLC (70361) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | |
| A049503 | Tier 1 | 3.0 | Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04950300 | 26.69 | 2/14/2023 | None | Ethanol - Cellulosic | RING-NECK ENERGY & FEED, LLC (6274) | RING-NECK ENERGY & FEED, LLC (70361) | Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | |
| A049505 | Tier 1 | 3.0 | Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A04950500 | 77.07 | 2/14/2023 | None | Ethanol | RING-NECK ENERGY & FEED, LLC (6274) | RING-NECK ENERGY & FEED, LLC (70361) | Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | |
| A049506 | Tier 1 | 3.0 | Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A04950600 | 69.04 | 2/14/2023 | None | Ethanol | RING-NECK ENERGY & FEED, LLC (6274) | RING-NECK ENERGY & FEED, LLC (70361) | Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | None | |
| A050601 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations | Louisiana | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A05060100 | 59.61 | 2/17/2023 | None | Bio-LNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations | None | |
| A050602 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | Louisiana | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A05060200 | 62.70 | 2/17/2023 | None | Bio-LNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | None | |
| A050702 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations | Canada | Landfill Gas (025) | Liquefied Natural Gas (LNG) | None | None | LNG025A05070200 | 51.26 | 2/24/2023 | None | Bio-LNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations | None | |
| A050703 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | Canada | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN025A05070300 | 54.35 | 2/24/2023 | None | Bio-LNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | None | |
| A027201 | Tier 1 | 3.0 | Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A02720100 | 65.63 | ETH009A02720101 | 65.00 | 10/21/2020 | None | Ethanol | Husker Ag LLC (5078) | Husker Ag LLC (70151) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. | 2021 AFPR Recert Complete | |
| B001801 | Tier 2 | 3.0 | Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA | Washington | (animal and poultry fat | Renewable Diesel (RND) | RND002B00180100 | 26.92 | RND002B00180102 | 35.02 | 12/6/2019 | None | Renewable Diesel | BP Products North America, Inc (4320) | Cherry Point Refinery (83736) | U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA | 2021 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A010002 | Tier 1 | 3.0 | Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01000200 | 67.48 | ETH009A01000201 | 67.11 | 6/7/2019 | None | Ethanol | The Andersons, Inc (5872) | The Andersons Denison Ethanol (70135) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A011501 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | Texas | Vastewater Sludge (030 | Compressed Natural Gas (CNG) | CNG030A01150100 | 37.33 | CNG030A01150101 | 36.77 | 12/19/2019 | None | Bio-CNG | Anew RNG, LLC (5877) | Ameresco San Antonio Biogas (71204) | Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | 2021 AFPR Recert Complete | Retired |
| A013002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01300200 | 67.34 | ETH009A01300201 | 65.09 | 9/24/2019 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A013901 | Tier 1 | 3.0 | Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A01390100 | 62.81 | ETH009A01390102 | 65.76 | 9/9/2019 | None | Ethanol | Midwest Renewable Energy (5214) | Midwest Renewable Energy (70160) | Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A014501 | Tier 1 | 3.0 | Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A01450100 | 69.60 | ETH009A01450102 | 68.61 | 8/6/2019 | None | Ethanol | Redfield Energy, LLC (4061) | Redfield Energy, LLC (70111) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A014601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | Michigan | Corn (009) | Ethanol (ETH) | ETH009A01460100 | 72.59 | ETH009A01460101 | 72.29 | 9/24/2019 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A014602 | Tier 1 | 3.0 | Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | Michigan | Corn (009) | Ethanol (ETH) | ETH009A01460200 | 67.10 | ETH009A01460201 | 66.61 | 9/24/2019 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01500100 | 74.83 | ETH009A01500101 | 74.03 | 10/3/2019 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01500200 | 68.05 | ETH009A01500201 | 67.28 | 10/14/2019 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015101 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01510100 | 74.44 | ETH009A01510101 | 73.56 | 10/3/2019 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01520100 | 74.15 | ETH009A01520101 | 72.75 | 10/3/2019 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01520200 | 67.32 | ETH009A01520201 | 65.82 | 10/3/2019 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A015401 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional) | Kentucky | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01540100 | 54.66 | CNG025A01540102 | 54.69 | 11/5/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015402 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional) | Kentucky | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A01540200 | 71.50 | LNG025A01540202 | 72.09 | 11/5/2019 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015403 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional) | Kentucky | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A01540300 | 74.59 | LCN025A01540302 | 75.18 | 11/5/2019 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| A015102 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01510200 | 67.72 | ETH009A01510201 | 66.14 | 10/3/2019 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A015501 | Tier 1 | 3.0 | Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01550100 | 67.97 | ETH009A01550101 | 67.61 | 9/24/2019 | None | Ethanol | Absolute Energy, LLC (5049) | Absolute Energy, LLC (70144) | Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI | 2021 AFPR Recert Complete | |
| A016401 | Tier 1 | 3.0 | Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. | | Corn (009) | Ethanol (ETH) | ETH009A01640100 | 67.23 | ETH009A01640101 | 66.71 | 10/15/2019 | None | Ethanol | BUSHMILLS ETHANOL, INC. (4063) | BUSHMILLS ETHANOL, INC. (70109) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. | 2021 AFPR Recert Complete | |
| B004701 | Tier 2 | 3.0 | Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California | Wyoming | Soybean Oil (005) | Renewable Diesel (RND) | RND005B00470100 | 58.34 | RND005B00470102 | 57.20 | 12/27/2019 | None | Renewable Diesel | Wyoming Renewable Diesel Company LLC (1440) | Wyoming Renewable Diesel Company LLC (82441) | Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California | 2021 AFPR Recert Complete | |
| A019501 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01950100 | 43.37 | CNG025A01950101 | 44.78 | 12/31/2019 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060) | Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional) | 2021 AFPR Recert Complete | Retired |
| B005901 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00590101 | -562.50 | ELC026B00590102 | -568.21 | 3/25/2021 | None | Electricity | California Bioenergy LLC (B194) | ABEC Bidart-Old River LLC (F00113) | Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | 2021 AFPR Recert Complete | Retired |
| B006001 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00600100 | -255.74 | CNG026B00600102 | -237.77 | 2/24/2020 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Fair Oaks Upgrader, LLC (71001) | Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California | 2021 AFPR Recert Complete | |
| A020901 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02090100 | 73.74 | ETH009A02090102 | 72.71 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | |
| A020902 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02090200 | 70.47 | ETH009A02090201 | 67.82 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A020903 | Tier 1 | 3.0 | Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02090300 | 66.86 | ETH009A02090301 | 64.08 | 6/24/2020 | None | Ethanol | Dakota Ethanol, LLC (4810) | Dakota Ethanol, LLC (70083) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | |
| B007201 | Tier 2 | 3.0 | Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use | Oregon | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00720100 | -188.78 | CNG026B00720102 | -171.65 | 9/30/2020 | None | Bio-CNG | IOGEN D3 BIOFUEL PARTNERS II LLC (7180) | WOF PNW Threemile Project (F00100) | Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| A021202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California | Missouri | Corn (009) | Ethanol (ETH) | ETH009A02120200 | 65.67 | ETH009A02120201 | 64.95 | 4/28/2020 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A021301 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02130100 | 61.55 | ETH009A02130101 | 61.55 | 6/22/2020 | None | Ethanol | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI | 2021 AFPR Recert Complete | Retired |
| A021701 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | North Dakota | Corn (009) | Ethanol (ETH) | ETH009A02170100 | 69.84 | ETH009A02170101 | 68.72 | 7/27/2020 | None | Ethanol | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| A021702 | Tier 1 | 3.0 | Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | North Dakota | Corn (009) | Ethanol (ETH) | ETH009A02170200 | 66.96 | ETH009A02170201 | 65.89 | 7/27/2020 | None | Ethanol | Hankinson Renewable Energy, LLC (6169) | Hankinson Renewable Energy, LLC (70288) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| A021901 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG | Canada | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02190100 | 38.64 | CNG025A02190101 | 31.80 | 6/22/2020 | None | Bio-CNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG | 2021 AFPR Recert Complete | |
| A021902 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California | Canada | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02190200 | 51.69 | LNG025A02190201 | 45.63 | 6/22/2020 | None | Bio-LNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California | 2021 AFPR Recert Complete | |
| A021903 | Tier 1 | 3.0 | Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | Canada | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02190300 | 54.77 | LCN025A02190301 | 48.72 | 6/22/2020 | None | Bio-LNG | EBI ENERGIE INC. (6459) | SAINT-THOMAS BIOMETHANE PLANT (71254) | Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2021 AFPR Recert Complete | |
| A022401 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02240100 | 69.32 | ETH009A02240102 | 73.00 | 6/24/2020 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A022402 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02240200 | 66.23 | ETH009A02240202 | 68.00 | 6/24/2020 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| B010901 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01090100 | -453.10 | CNG026B01090102 | -288.39 | 9/30/2020 | None | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B010902 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01090200 | -308.48 | CNG026B01090202 | -278.19 | 9/30/2020 | None | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B010903 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01090300 | -236.96 | CNG026B01090302 | -247.83 | 9/30/2020 | None | Bio-CNG | Clean Energy (5481) | Maple Leaf/Grotegut RNG Facility (F00167) | Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B009601 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00960100 | -532.74 | CNG026B00960102 | -372.40 | 9/30/2020 | None | Bio-CNG | Clean Energy (5481) | Calumet - Dairy Dreams (F00127) | Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B009701 | Tier 2 | 3.0 | Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00970100 | -372.20 | CNG026B00970101 | -445.37 | 9/30/2020 | None | Bio-CNG | Clean Energy (5481) | Calumet - Ponderosa (F00128) | Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B010202 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020200 | -289.76 | CNG026B01020201 | -392.30 | 12/3/2020 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B010203 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020300 | -308.74 | CNG026B01020301 | -399.36 | 12/3/2020 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| A023301 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional) | Kansas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02330100 | 45.91 | CNG025A02330102 | 47.10 | 7/24/2020 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| B010801 | Tier 2 | 3.0 | Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01080100 | -230.13 | CNG026B01080101 | -240.91 | 9/30/2020 | None | Bio-CNG | AgPower Jerome, LLC (C1036) | AgPower Jerome RNG Project (F00077) | Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| A026501 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02650100 | 73.16 | ETH009A02650101 | 71.88 | 10/9/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | HUB CITY ENERGY LLC (70721) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI | 2021 AFPR Recert Complete | |
| A024501 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02450100 | 69.92 | ETH009A02450103 | 73.16 | 12/4/2020 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A024502 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02450200 | 62.54 | ETH009A02450203 | 64.79 | 12/4/2020 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A024201 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02420100 | 47.53 | CNG025A02420102 | 57.00 | 10/29/2020 | None | Bio-CNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | Ohio | Corn (009) | Ethanol (ETH) | ETH009A02460100 | 77.21 | ETH009A02460101 | 76.22 | 12/29/2020 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A024602 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | Ohio | Corn (009) | Ethanol (ETH) | ETH009A02460200 | 69.47 | ETH009A02460201 | 68.53 | 12/29/2020 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A024701 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02470100 | 49.78 | CNG025A02470102 | 48.20 | 10/13/2020 | None | Bio-CNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG | 2021 AFPR Recert Complete | Retired |
| A024901 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02490100 | 74.54 | ETH009A02490102 | 76.29 | 7/24/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | 2021 AFPR Recert Complete | Retired |
| A024902 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02490200 | 67.28 | ETH009A02490201 | 68.82 | 7/24/2020 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | 2021 AFPR Recert Complete | Retired |
| A026701 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02670100 | 35.51 | CNG025A02670102 | 35.69 | 3/18/2021 | None | Bio-CNG | Anew RNG, LLC (5877) | Johnstown Regional Energy - Raeger (71131) | Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG | 2021 AFPR Recert Complete | |
| A026403 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02640300 | 60.28 | CNG025A02640302 | 58.15 | 3/17/2021 | None | Bio-CNG | Anew RNG, LLC (5877) | Johnstown Regional Energy - Southern Alleghenies (71133) | Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG | 2021 AFPR Recert Complete | |
| A027401 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional) | Texas | Vastewater Sludge (030 | Compressed Natural Gas (CNG) | CNG030A02740100 | 38.37 | CNG030A02740102 | 41.71 | 3/1/2021 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Renovar Arlington, LTD RNG Project (70501) | Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B012701 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01270100 | -417.35 | CNG026B01270102 | -419.62 | 12/31/2020 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B012702 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01270200 | -417.27 | CNG026B01270201 | -420.14 | 12/31/2020 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B012703 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01270300 | -418.90 | CNG026B01270302 | -420.70 | 12/31/2020 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| B012704 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01270400 | -392.44 | CNG026B01270401 | -410.41 | 12/31/2020 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029501 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02950100 | 21.93 | BIO001A02950101 | 22.03 | 4/1/2021 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | 2021 AFPR Recert Complete | Retired |
| A029502 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | California | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02950200 | 16.98 | BIO001A02950201 | 16.71 | 4/1/2021 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | 2021 AFPR Recert Complete | Retired |
| A029702 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Kansas | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02970200 | 61.43 | LCN025A02970201 | 63.59 | 12/15/2020 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| A029801 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional) | Washington | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02980100 | 28.24 | CNG025A02980101 | 28.80 | 3/12/2021 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| A029802 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | Washington | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02980200 | 41.09 | LNG025A02980201 | 42.58 | 3/12/2021 | None | Bio-LNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| A029803 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | Washington | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02980300 | 44.18 | LCN025A02980301 | 45.67 | 3/12/2021 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| A030601 | Tier 1 | 3.0 | Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03060100 | 41.93 | CNG025A03060101 | 42.85 | 4/6/2021 | None | Bio-CNG | MONROEVILLE LFG, LLC (6317) | MONROEVILLE LFG, LLC (71136) | Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| B014301 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B01430100 | -429.05 | CNG044B01430101 | -432.11 | 6/29/2021 | None | Bio-CNG | Anew RNG, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations | 2021 AFPR Recert Complete | Retired |
| A030902 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A03090200 | 71.95 | ETH009A03090201 | 72.02 | 5/4/2021 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| B014901 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B01490100 | -359.66 | CNG044B01490101 | -319.70 | 6/29/2021 | None | Bio-CNG | Anew RNG, LLC (5877) | South Meadows Farm (F00195) | Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California | 2021 AFPR Recert Complete | |
| B016501 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01650100 | -406.35 | CNG026B01650101 | -392.30 | 9/30/2021 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| A033001 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03300100 | 73.75 | ETH009A03300101 | 73.79 | 3/1/2021 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B016301 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. | California | Dairy Manure (026) | Electricity (ELC) | ELC026B01630100 | -758.46 | ELC026B01630101 | -756.24 | 6/21/2021 | None | Electricity | CleanFuture, Inc. (C1001) | Hilarides (F00006) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. | 2021 AFPR Recert Complete | |
| B017301 | Tier 2 | 3.0 | Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California | Idaho | Dairy Manure (026) | Electricity (ELC) | ELC026B01730100 | -545.71 | ELC026B01730101 | -548.10 | 9/22/2021 | None | Electricity | DF-AP #1, LLC (C1122) | Big Sky Dairy Digester (F00329) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California | 2021 AFPR Recert Complete | Retired |
| B017402 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | South Dakota | Corn (009) | Ethanol (ETH) | ETH009B01740200 | 68.73 | ETH009B01740201 | 69.33 | 9/24/2021 | None | Ethanol | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| B017401 | Tier 2 | 3.0 | Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | South Dakota | Corn (009) | Ethanol (ETH) | ETH009B01740100 | 75.91 | ETH009B01740101 | 76.65 | 9/24/2021 | None | Ethanol | POET Biorefining - Big Stone (4736) | POET Biorefining - Big Stone (70025) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | |
| A034501 | Tier 1 | 3.0 | Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03450100 | 52.66 | CNG025A03450101 | 53.05 | 6/16/2021 | None | Bio-CNG | WESTSIDE GAS PRODUCERS, LLC (6218) | WESTSIDE GAS PRODUCERS, LLC (71151) | Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. | 2021 AFPR Recert Complete | Retired |
| A035101 | Tier 1 | 3.0 | Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03510100 | 65.93 | ETH009A03510101 | 67.49 | 6/1/2021 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A036703 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional) | Tennessee | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A03670300 | 65.26 | LCN025A03670301 | 66.26 | 5/11/2021 | None | Bio-CNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| A036702 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional) | Tennessee | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A03670200 | 62.18 | LNG025A03670201 | 63.18 | 5/11/2021 | None | Bio-LNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| A037501 | Tier 1 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03750100 | 37.82 | CNG025A03750101 | 38.37 | 8/20/2021 | None | Bio-CNG | BLUE SOURCE LLC (6086) | Seabreeze Energy Producers (70281) | Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| B019101 | Tier 2 | 3.0 | Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. | California | n Landscaping Waste ( | Compressed Natural Gas (CNG) | CNG028B01910100 | 2.51 | CNG028B01910101 | 72.26 | 6/29/2021 | None | Bio-CNG | California Renewable Power LLC(C196) | California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270) | Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. | 2021 AFPR Recert Complete | |
| B021901 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02190100 | -412.71 | CNG044B02190101 | -359.22 | 9/30/2021 | None | Bio-CNG | Anew RNG, LLC (5877) | HOMAN FARM (71343) | RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | Retired |
| A008801 | Tier 1 | 3.0 | Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California | Colorado | Corn (009) | Ethanol (ETH) | ETH009A00880100 | 64.61 | ETH009A00880101 | 64.00 | 5/17/2019 | None | Ethanol | Yuma Ethanol, LLC (4735) | Yuma Ethanol, LLC (70024) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A019801 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A01980100 | 61.26 | ETH009A01980103 | 62.37 | 6/24/2020 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI | 2021 AFPR Recert Complete | Retired |
| A021302 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A02130200 | 21.31 | ETH012A02130203 | 21.93 | 6/22/2020 | None | Ethanol - Cellulosic | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| B007901 | Tier 2 | 3.0 | Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B00790100 | 30.48 | RND002B00790103 | 34.32 | 9/30/2020 | Application Package | Renewable Diesel | Kern Oil & Refining Co. (5038) | Kern Oil & Refining Co. (80105) | Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution | 2021 AFPR Recert Complete | |
| B007902 | Tier 2 | 3.0 | Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B00790200 | 41.85 | RND002B00790203 | 43.24 | 9/30/2020 | Application Package | Renewable Diesel | Kern Oil & Refining Co. (5038) | Kern Oil & Refining Co. (80105) | Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution | 2021 AFPR Recert Complete | |
| B010201 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | Texas | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01020101 | -408.62 | CNG026B01020106 | -403.57 | 12/3/2020 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Greengasco, LLC (F00154) | Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use | 2021 AFPR Recert Complete | |
| A025901 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Distillers' Corn Oil (003 | Biodiesel (BIO) | BIO003A02590100 | 36.62 | BIO003A02590102 | 37.49 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A025902 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | Soybean Oil (005) | Biodiesel (BIO) | BIO003A02590100 | 36.62 | BIO005A02590202 | 66.85 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A025903 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | Tennessee | (animal and poultry fat | Biodiesel (BIO) | BIO003A02590100 | 36.62 | BIO002A02590302 | 42.58 | 11/6/2020 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (80316) | U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A029002 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | Illinois | Soybean Oil (005) | Biodiesel (BIO) | BIO005A02900200 | 57.00 | BIO005A02900201 | 58.00 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | 2021 AFPR Recert Complete | Retired |
| A029003 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | Illinois | Canola Oil (006) | Biodiesel (BIO) | BIO006A02900300 | 53.00 | BIO006A02900301 | 54.50 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | 2021 AFPR Recert Complete | |
| A029006 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | Illinois | oking Oil/Waste Oil (UC | Biodiesel (BIO) | BIO001A02900600 | 20.25 | BIO001A02900601 | 22.00 | 6/8/2021 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | 2021 AFPR Recert Complete | Retired |
| A030401 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional) | California | Vastewater Sludge (030 | Compressed Natural Gas (CNG) | CNG030A03040100 | 30.31 | CNG030A03040102 | 38.91 | 6/14/2021 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Point Loma Digester Gas Project (F00027) | Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018502 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01850200 | -388.91 | CNG026B01850201 | -366.51 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| B018701 | Tier 2 | 3.0 | Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional) | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01870100 | -435.22 | CNG026B01870101 | -421.53 | | Application Package | Bio-CNG | Dry Creek RNG LLC (C1098) | Dry Creek RNG Project (F00342) | Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| B019801 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980100 | -388.29 | CNG026B01980101 | -294.40 | 9/30/2021 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| A039401 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03940100 | 66.71 | ETH009A03940101 | 66.77 | 10/14/2021 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. | 2021 AFPR Recert Complete | Retired |
| B020702 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02070200 | -211.01 | CNG026B02070201 | -193.95 | 12/29/2021 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| B020701 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02070100 | -135.37 | CNG026B02070101 | -132.51 | 12/29/2021 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional) | 2021 AFPR Recert Complete | Retired |
| A040201 | Tier 1 | 3.0 | Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A04020100 | 63.73 | ETH009A04020101 | 63.80 | 10/11/2021 | None | Ethanol | Siouxland Ethanol, LLC (5026) | Siouxland Ethanol (70134) | Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional) | 2021 AFPR Recert Complete | |
| B021601 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02160100 | -382.83 | CNG026B02160101 | -333.34 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| B021603 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | LCN026B02160300 | -366.02 | LCN026B02160301 | -315.22 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| B021602 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | LNG026B02160200 | -369.56 | LNG026B02160201 | -318.76 | 3/30/2022 | Application Package | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional) | 2021 AFPR Recert Complete | Retired |
| B021702 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | LNG026B02170200 | -290.16 | LNG026B02170201 | -259.30 | 3/30/2022 | Application Package | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional) | 2021 AFPR Recert Complete | Retired |
| B021703 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | LCN026B02170300 | -286.62 | LCN026B02170301 | -255.76 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B021701 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02170100 | -303.92 | CNG026B02170101 | -274.25 | 3/30/2022 | Application Package | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| B022001 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02200101 | -410.57 | CNG044B02200102 | -370.44 | 12/31/2021 | Application Package | Bio-CNG | Anew RNG, LLC (5877) | SOMERSET FARM (71381) | Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional) | 2021 AFPR Recert Complete | Retired |
| A041601 | Tier 1 | 3.0 | Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A04160100 | 66.18 | CNG025A04160101 | 71.21 | 11/23/2021 | None | Bio-CNG | TRUSTAR ENERGY LLC (6523) | Greentree Landfill Gas Company (F00212) | Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A042301 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A04230100 | 70.88 | ETH009A04230101 | 72.01 | 10/26/2021 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A037803 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03780300 | 66.28 | ETH010A03780301 | 66.40 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A037805 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03780500 | 73.81 | ETH010A03780502 | 74.69 | 9/29/2021 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (70039) | Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B025106 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Diesel (RND) | RND002B02510600 | 42.48 | RND002B02510601 | 47.48 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025112 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B02511200 | 42.48 | RNT002B02511201 | 47.48 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B026802 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B02680200 | 18.87 | RND002B02680201 | 18.93 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B026810 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B02681000 | 29.26 | AJF002B02681001 | 29.78 | 3/28/2022 | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B026812 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B02681200 | 29.26 | RNT002B02681201 | 29.78 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B026811 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | California | (animal and poultry fat | Renewable Diesel (RND) | RND002B02681100 | 29.26 | RND002B02681101 | 29.78 | 3/28/2022 | Application Package | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B026803 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | California | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B02680300 | 18.87 | RNT002B02680301 | 18.93 | 3/28/2022 | Application Package | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B026801 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | California | (animal and poultry fat | Alternative Jet Fuel (AJF) | AJF002B02680100 | 18.87 | AJF002B02680101 | 18.93 | | Application Package | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B036901 | Tier 2 | 3.0 | Fuel Producer: MONTAUK ENERGY HOLDINGS, LLC (6139); Facility Name: Pico Energy, LLC (71221); Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional) | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03690100 | -260.56 | 3/27/2023 | Application Package | Bio-CNG | MONTAUK ENERGY HOLDINGS, LLC (6139) | Pico Energy, LLC (71221) | Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional) | None | |
| A048801 | Tier 1 | 3.0 | Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional) | Kansas | Corn (009) | Ethanol (ETH) | None | None | ETH009A04880100 | 62.50 | 3/14/2023 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional) | None | |
| A048802 | Tier 1 | 3.0 | Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A04880200 | 65.50 | 3/14/2023 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional) | None | |
| A048803 | Tier 1 | 3.0 | Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional) | Kansas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04880300 | 24.50 | 3/14/2023 | None | Ethanol | Western Plains Energy, LLC (4740) | Western Plains Energy, LLC (70030) | Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional) | None | |
| B038201 | Tier 2 | 3.0 | Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B03820100 | -758.40 | 3/28/2023 | Application Package | Electricity | Madera Renewable Energy, LLC (C1140) | Madera Renewable Energy, LLC (F00436) | Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional) | None | Retired |
| B039301 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY CLOVER HILL (71261); Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03930100 | -204.42 | 3/30/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | U.S. GAIN RNG FACILITY CLOVER HILL (71261) | Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional) | None | |
| B040101 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04010100 | -216.27 | 3/30/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET SWISS VALLEY RNG PROJECT (71161) | Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional) | None | Retired |
| B040401 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: AUGEAN RNG PROJECT (71081); Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional) | Washington | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04040100 | -216.63 | 3/28/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | AUGEAN RNG PROJECT (71081) | Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional) | None | |
| B042001 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: RIALTO Bioenergy (F00475); Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional) | California | ood Scraps/Waste (02 | Compressed Natural Gas (CNG) | None | None | CNG027B04200100 | -28.20 | 3/22/2023 | Application Package | Bio-CNG | Anew RNG, LLC (5877) | RIALTO Bioenergy (F00475) | Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional) | None | |
| B042801 | Tier 2 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | Mississippi | Distillers' Corn Oil (003 | Renewable Diesel (RND) | RND003A02710100 | 78.60 | RND003B04280100 | 51.80 | 3/30/2023 | Application Package | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | None | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B042802 | Tier 2 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | Mississippi | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04280200 | 80.81 | 3/30/2023 | Application Package | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | None | Retired |
| A049701 | Tier 1 | 3.0 | Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | Canada | Soybean Oil (005) | Biodiesel (BIO) | None | None | BIO005A04970100 | 59.69 | 4/21/2023 | None | Biodiesel | Canary Biofuels Inc. (1773) | Canary 1 (F00502) | Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | None | |
| A049702 | Tier 1 | 3.0 | Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | Canada | Canola Oil (006) | Biodiesel (BIO) | None | None | BIO006A04970200 | 54.45 | 4/21/2023 | None | Biodiesel | Canary Biofuels Inc. (1773) | Canary 1 (F00502) | Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | None | |
| A049703 | Tier 1 | 3.0 | Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | Canada | Distillers' Corn Oil (003 | Biodiesel (BIO) | None | None | BIO003A04970300 | 29.99 | 4/21/2023 | None | Biodiesel | Canary Biofuels Inc. (1773) | Canary 1 (F00502) | Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | None | |
| A049704 | Tier 1 | 3.0 | Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | Canada | (animal and poultry fat | Biodiesel (BIO) | None | None | BIO002A04970400 | 34.62 | 4/21/2023 | None | Biodiesel | Canary Biofuels Inc. (1773) | Canary 1 (F00502) | Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | None | |
| A049705 | Tier 1 | 3.0 | Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | Canada | oking Oil/Waste Oil (UC | Biodiesel (BIO) | None | None | BIO001A04970500 | 22.66 | 4/21/2023 | None | Biodiesel | Canary Biofuels Inc. (1773) | Canary 1 (F00502) | Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional) | None | |
| A051201 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A02940201 | 62.64 | ETH009A05120100 | 63.80 | 5/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | None | Retired |
| A051202 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A02940101 | 71.64 | ETH009A05120200 | 72.75 | 5/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | None | Retired |
| A051203 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A02940401 | 65.71 | ETH010A05120300 | 65.71 | 5/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | None | Retired |
| A051204 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A02940301 | 74.71 | ETH010A05120400 | 74.66 | 5/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional) | None | Retired |
| A005101 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00510100 | 69.86 | ETH009A00510102 | 70.77 | 5/7/2019 | None | Ethanol | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005102 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00510200 | 30.32 | ETH012A00510202 | 30.54 | 5/7/2019 | None | Ethanol - Cellulosic | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A049601 | Tier 1 | 3.0 | Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. AI ; Ethanol transported by rail to California (Provisional) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A04960100 | 23.77 | 4/26/2023 | None | Ethanol - Cellulosic | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. AI ; Ethanol transported by rail to California (Provisional) | None | |
| A049602 | Tier 1 | 3.0 | Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A04960200 | 63.19 | 4/26/2023 | None | Ethanol | Siouxland Energy Cooperative (4060) | Siouxland Energy Cooperative (70112) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional) | None | |
| A020001 | Tier 1 | 3.0 | Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02000100 | 40.13 | CNG025A02000101 | 37.64 | 6/29/2020 | None | Bio-CNG | GHI Energy, LLC (6156) | Waste Management American Landfill (70421) | Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional) | 2021 AFPR Recert Complete | Retired |
| B025104 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Diesel (RND) | RND001B02510400 | 18.16 | RND001B02510401 | 17.92 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025101 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Soybean Oil (005) | Renewable Diesel (RND) | RND005B02510100 | 60.13 | RND005B02510101 | 57.13 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025107 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Soybean Oil (005) | Renewable Naphtha (RNT) | RNT005B02510700 | 60.13 | RNT005B02510701 | 57.13 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025109 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Naphtha (RNT) | RNT001B02510900 | 19.75 | RNT001B02510901 | 19.77 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025108 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | Distillers' Corn Oil (003 | Renewable Naphtha (RNT) | RNT003B02510800 | 27.64 | RNT003B02510801 | 28.00 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025110 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | oking Oil/Waste Oil (UC | Renewable Naphtha (RNT) | RNT001B02511000 | 18.16 | RNT001B02511001 | 17.92 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025111 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Naphtha (RNT) | RNT002B02511100 | 32.14 | RNT002B02511101 | 33.08 | 3/28/2022 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| B025102 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. | Louisiana | Distillers' Corn Oil (003 | Renewable Diesel (RND) | RND003B02510200 | 27.64 | RND003B02510201 | 28.00 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. | 2021 AFPR Recert Complete | |
| B025103 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. | Louisiana | oking Oil/Waste Oil (UC | Renewable Diesel (RND) | RND001B02510300 | 19.75 | RND001B02510301 | 19.77 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. | 2021 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B025105 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | Louisiana | (animal and poultry fat | Renewable Diesel (RND) | RND002B02510500 | 32.14 | RND002B02510501 | 33.08 | 3/28/2022 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional) | 2021 AFPR Recert Complete | |
| A038602 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A03860200 | 69.20 | ETH009A03860201 | 69.61 | 7/13/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A038601 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A03860100 | 72.20 | ETH009A03860101 | 72.76 | 7/13/2021 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional) | 2021 AFPR Recert Complete | Retired |
| A050201 | Tier 1 | 3.0 | Fuel Producer: Plymouth Energy LLC (5474) ; Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01250200 | 68.41 | ETH009A05020100 | 63.91 | 5/18/2023 | None | Ethanol | Plymouth Energy LLC (5474) | Plymouth Energy LLC (70183) | Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional) | None | |
| L021101 | Lookup Table | 3.0 | Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade Inc (F00567); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC049L00072019 | 0.00 | 2/17/2023 | None | Electricity | SRECTrade, Inc (C1018) | SRECTrade Inc (F00567) | Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California | None | |
| A051801 | Tier 1 | 3.0 | Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG | Oregon | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | None | None | LCN026A05180100 | -156.47 | 5/26/2023 | None | Bio-LNG | IOGEN D3 BIOFUEL PARTNERS II LLC (7180) | ResilientIG Threemile Acquisition LLC (F00100) | Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG | None | |
| A051802 | Tier 1 | 3.0 | Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG | Oregon | Dairy Manure (026) | Liquefied Natural Gas (LNG) | None | None | LNG026A05180200 | -152.93 | 5/26/2023 | None | Bio-LNG | IOGEN D3 BIOFUEL PARTNERS II LLC (7180) | ResilientIG Threemile Acquisition LLC (F00100) | Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG | None | |
| A005301 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00530100 | 73.81 | ETH009A00530103 | 72.85 | 5/6/2019 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005302 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00530200 | 66.94 | ETH009A00530203 | 65.95 | 5/6/2019 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005303 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00530300 | 26.95 | ETH012A00530303 | 25.98 | 5/6/2019 | None | Ethanol - Cellulosic | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry  DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00520100 | 75.97 | ETH009A00520103 | 74.36 | 5/6/2019 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00520200 | 68.75 | ETH009A00520203 | 66.04 | 5/6/2019 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A005203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00520300 | 28.78 | ETH012A00520303 | 26.29 | 5/6/2019 | None | Ethanol - Cellulosic | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A006101 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00610100 | 76.85 | ETH009A00610102 | 75.21 | 6/5/2019 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A006102 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00610200 | 69.76 | ETH009A00610202 | 65.67 | 6/5/2019 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A006103 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00610300 | 29.51 | ETH012A00610302 | 26.04 | 6/5/2019 | None | Ethanol - Cellulosic | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A012701 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN;  Ethanol transported by rail to California | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A01270100 | 28.33 | ETH012A01270103 | 28.29 | 9/24/2019 | None | Ethanol - Cellulosic | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN;  Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A012702 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01270200 | 75.89 | ETH009A01270203 | 77.34 | 9/24/2019 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A012703 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01270300 | 67.79 | ETH009A01270303 | 68.22 | 9/24/2019 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005601 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00560100 | 74.83 | ETH009A00560102 | 73.89 | 6/10/2019 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005602 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00560200 | 68.44 | ETH009A00560202 | 67.49 | 6/10/2019 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005603 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00560300 | 28.47 | ETH012A00560302 | 28.27 | 6/10/2019 | None | Ethanol - Cellulosic | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005801 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00580100 | 81.17 | ETH009A00580102 | 73.74 | 5/7/2019 | None | Ethanol | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A005802 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00580200 | 71.82 | ETH009A00580202 | 68.00 | 5/7/2019 | None | Ethanol | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A005803 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00580300 | 31.75 | ETH012A00580302 | 28.21 | 5/7/2019 | None | Ethanol - Cellulosic | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A006401 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00640100 | 75.04 | ETH009A00640102 | 72.37 | 5/7/2019 | None | Ethanol | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A006403 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00640300 | 27.72 | ETH012A00640302 | 24.60 | 5/7/2019 | None | Ethanol - Cellulosic | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA,  using BPX conversion method; Ethanol transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A013501 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A01350100 | 32.07 | BIO002A01350102 | 31.65 | 12/20/2019 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A014101 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | Missouri | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003A01410100 | 29.40 | BIO003A01410102 | 27.16 | 9/25/2019 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441) | Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A014102 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | Missouri | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A01410200 | 34.21 | BIO002A01410202 | 32.08 | 9/25/2019 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441) | Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | 2021 AFPR Recert Complete | Retired |
| A028201 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A02820100 | 27.02 | BIO002A02820102 | 24.60 | 11/20/2020 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail | 2021 AFPR Recert Complete | Retired |
| A027901 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | Arkansas | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003A02790100 | 33.97 | BIO003A02790101 | 33.53 | 3/9/2021 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| A027902 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | Arkansas | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02790200 | 27.05 | BIO001A02790202 | 26.13 | 3/9/2021 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional) | 2021 AFPR Recert Complete | Retired |
| B028001 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | California | Swine Manure (044) | Gaseous Hydrogen (HYG) | HYG044B02800100 | -374.14 | HYG044B02800101 | -296.05 | 6/7/2023 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | None | |
| B028002 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | California | Swine Manure (044) | Gaseous Hydrogen (HYG) | HYG044B02800200 | -390.47 | HYG044B02800201 | -368.94 | 6/7/2023 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California. | None | |
| B037802 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | California | Landfill Gas (025) | Gaseous Hydrogen (HYG) | HYG025B03780200 | 75.16 | HYG025B03780201 | 99.94 | 6/7/2023 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A023201 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02320100 | 43.15 | CNG025A02320101 | 42.66 | 7/24/2020 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Renovar Arlington, LTD RNG Project (70501) | Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. | 2021 AFPR Recert Complete | |
| B038301 | Tier 2 | 3.0 | Fuel Producer: EEC MARKET GROUP LLC (6496); Facility Name: NLC Energy Denmark LLC (70242); Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03830100 | -284.21 | 6/22/2023 | Application Package | Bio-CNG | EEC MARKET GROUP LLC (6496) | NLC Energy Denmark LLC (70242) | Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional) | None | |
| B042603 | Tier 2 | 3.0 | Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California. | California | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031B04260300 | 142.27 | 6/23/2023 | Application Package | Hydrogen | Iwatani Corporation of America (C1024) | Linde-Praxair (F00088) | Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California. | None | |
| A050801 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Eugene/Springfield Water Pollution Control Facility (F00546); RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional) | Oregon | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | None | None | CNG030A05080100 | 34.26 | 6/23/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Eugene/Springfield Water Pollution Control Facility (F00546) | RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional) | None | |
| B041601 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Canola Oil (006) | Renewable Diesel (RND) | RND005B02400200 | 57.64 | RND006B04160100 | 51.93 | 6/28/2023 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041602 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional) | North Dakota | Distillers' Corn Oil (003) | Renewable Diesel (RND) | RND003B02400100 | 29.79 | RND003B04160200 | 29.65 | 6/28/2023 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional) | None | |
| B041603 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313; U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02400301 | 33.43 | RND002B04160300 | 32.91 | 6/28/2023 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313 | U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041604 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Soybean Oil (005) | Renewable Diesel (RND) | RND005B02400200 | 57.64 | RND005B04160400 | 57.25 | 6/28/2023 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041605 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RND001B02400800 | 21.09 | RND001B04160500 | 20.19 | 6/28/2023 | Application Package | Renewable Diesel | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041606 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Canola Oil (006) | Renewable Naphtha (RNT) | None | None | RNT006B04160600 | 51.93 | 6/28/2023 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041607 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional) | North Dakota | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | RNT003B02400400 | 29.79 | RNT003B04160700 | 29.65 | 6/28/2023 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional) | None | |
| B041608 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02400701 | 33.43 | RNT002B04160800 | 32.91 | 6/28/2023 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B041609 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Soybean Oil (005) | Renewable Naphtha (RNT) | RNT005B02400500 | 57.64 | RNT005B04160900 | 57.25 | 6/28/2023 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Facility Name: Marathon Dickinson Refinery (F00313) | U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041610 | Tier 2 | 3.0 | Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | North Dakota | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | RNT001B02400600 | 21.09 | RNT001B04161000 | 20.19 | 6/28/2023 | Application Package | Renewable Naphtha | DAKOTA PRAIRIE REFINING (1166) | Marathon Dickinson Refinery (F00313) | U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional) | None | |
| B041701 | Tier 2 | 3.0 | Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | Oklahoma | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04170100 | 67.05 | 6/28/2023 | Application Package | Renewable Diesel | WYNNEWOOD REFINING COMPANY, LLC (4148) | WYNNEWOOD REFINING COMPANY (82420) | Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | None | |
| B041702 | Tier 2 | 3.0 | Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | Oklahoma | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B04170200 | 37.82 | 6/28/2023 | Application Package | Renewable Diesel | WYNNEWOOD REFINING COMPANY, LLC (4148) | WYNNEWOOD REFINING COMPANY (82420) | Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | None | |
| B042101 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | Louisiana | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04210100 | 61.50 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B042102 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B04210200 | 32.50 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042103 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04210300 | 26.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042104 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04210400 | 20.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042105 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04210500 | 26.50 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042106 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04210600 | 31.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042107 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04210700 | 37.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042108 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04210800 | 39.50 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B042109 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04210900 | 48.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042110 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04211000 | 24.00 | 6/29/2023 | Application Package | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | None | |
| B042111 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | Louisiana | Soybean Oil (005) | Renewable Naphtha (RNT) | None | None | RNT005B04211100 | 62.00 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B042112 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | None | None | RNT003B04211200 | 33.00 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042113 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B04211300 | 26.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042114 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B04211400 | 20.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042115 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B04211500 | 27.00 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042116 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B04211600 | 31.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042117 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B04211700 | 37.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042118 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B04211800 | 40.00 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042119 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B04211900 | 48.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042120 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B04212000 | 24.50 | 6/29/2023 | Application Package | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B042121 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212100 | 62.00 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B042122 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212200 | 33.00 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042123 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212300 | 26.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042124 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212400 | 20.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042125 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212500 | 27.00 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042126 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212600 | 31.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042127 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212700 | 37.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042128 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212800 | 40.00 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042129 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04212900 | 48.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042130 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | Louisiana | Other Organic Waste (029) | Propane (LPG) | None | None | LPG029B04213000 | 24.50 | 6/29/2023 | Application Package | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | None | |
| B042131 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | Louisiana | Soybean Oil (005) | Alternative Jet Fuel (AJF) | None | None | AJF005B04213100 | 62.00 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B042132 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Distillers' Corn Oil (003) | Alternative Jet Fuel (AJF) | None | None | AJF003B04213200 | 33.00 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B042133 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04213300 | 26.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042134 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04213400 | 20.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042135 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04213500 | 27.00 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042136 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04213600 | 31.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042137 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04213700 | 37.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042138 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04213800 | 40.00 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042139 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04213900 | 48.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker | None | |
| B042140 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | Louisiana | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04214000 | 24.50 | 6/29/2023 | Application Package | Alternative Jet Fuel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker | None | |
| B043001 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04300100 | -236.90 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | None | |
| B043002 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04300200 | -243.54 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | None | |
| B043003 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04300300 | -132.07 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional) | None | |
| B043004 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300400 | -275.67 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B043005 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300500 | -282.30 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional) | None | |
| B043006 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300600 | -170.83 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional) | None | |
| B043007 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300700 | -221.27 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | None | |
| B043008 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300800 | -227.91 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | None | |
| B043009 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04300900 | -116.43 | 6/27/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional) | None | |
| B039401 | Tier 2 | 3.0 | Fuel Producer: Chevron Products Company (5086) ; Facility Name: Chevron El Segundo (01013); Soybean oil transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (PROV3.0) | California | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B03940100 | 51.74 | 6/30/2023 | Application Package | Renewable Diesel | Chevron Products Company (5086) | Chevron El Segundo (01013) | Soybean oil  transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (Provisional) | None | |
| B039601 | Tier 2 | 3.0 | Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use.  (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03960100 | -411.32 | 6/30/2023 | Application Package | Bio-CNG | Lakeside Pipeline, LLC (C1158) | Lakeside Pipeline, LLC (F00480) | Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use.  (Provisional) | None | |
| B039602 | Tier 2 | 3.0 | Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California For transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03960200 | -416.41 | 6/30/2023 | Application Package | Bio-CNG | Lakeside Pipeline, LLC (C1158) | Lakeside Pipeline, LLC (F00480) | Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California For transportation use (Provisional) | None | |
| B039603 | Tier 2 | 3.0 | Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at River Ranch Dairy In Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use. (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03960300 | -417.71 | 6/30/2023 | Application Package | Bio-CNG | Lakeside Pipeline, LLC (C1158) | Lakeside Pipeline, LLC (F00480) | Biogas from dairy manure at River Ranch Dairy In Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use. (Provisional) | None | |
| B039604 | Tier 2 | 3.0 | Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Decade Dairy in Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B03960400 | -418.87 | 6/30/2023 | Application Package | Bio-CNG | Lakeside Pipeline, LLC (C1158) | Lakeside Pipeline, LLC (F00480) | Biogas from dairy manure at Decade Dairy in Hanford, CA;  upgraded to pipeline quality at Lakeside Pipeline, LLC;  pipelined to California for transportation use (Provisional) | None | |
| B040301 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Belonave Biogas LLC in  Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC; pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04030100 | -419.40 | 6/30/2023 | Application Package | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from dairy  manure at Belonave Biogas LLC in  Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC;  pipelined to California for transportation use (Provisional) | None | |
| A050101 | Tier 1 | 3.0 | Fuel Producer: BIOENERGETICA VALE DO PARACATU SA (1431); Facility Name: BIOENERGETICA VALE DO PARACATU SA (71521); Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck. (3.0) | Brazil | Sugarcane  (018) | Ethanol (ETH) | None | None | ETH018A05010100 | 50.89 | 7/3/2023 | None | Ethanol | BIOENERGETICA VALE DO PARACATU SA (1431) | BIOENERGETICA VALE DO PARACATU SA (71521) | Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck. | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B043801 | Tier 2 | 3.0 | Fuel Producer: Lone Oak Energy, LLC (C1177); Facility Name: Lone Oak Energy, LLC (F00542); Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04380100 | -404.74 | 6/30/2023 | Application Package | Bio-CNG | Lone Oak Energy, LLC (C1177) | Lone Oak Energy, LLC (F00542) | Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | |
| B045001 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEMETER RNG PROJECT (71302); Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04500100 | -191.29 | 6/30/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | DEMETER RNG PROJECT (71302) | Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | None | |
| B046701 | Tier 2 | 3.0 | Fuel Producer: Lime (C1014); Facility Name: Lime Headquarters (F00036); Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California. (3.0) | California | Solar (033) | Electricity (ELC) | None | None | ELC033B04670100 | 80.29 | 8/1/2023 | Application Package | Electricity | Lime (C1014) | Lime Headquarters (F00036) | Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California. | None | |
| L021801 | Lookup Table | 3.0 | Fuel Producer: Swift Transportation Company of Arizona, LLC (C1230) ; Facility Name: Swift Transportation Co. of Arizona, LLC. (F00642); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 7/7/2023 | None | Electricity | Swift Transportation Company of Arizona, LLC (C1230) | Swift Transportation Co. of Arizona, LLC. (F00642) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L021901 | Lookup Table | 3.0 | Fuel Producer: Prologis Mobility (C1234); Facility Name: Prologis Mobility LLC (F00637); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 7/20/2023 | None | Electricity | Prologis Mobility (C1234) | Prologis Mobility LLC (F00637) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L022001 | Lookup Table | 3.0 | Fuel Producer: TeraWatt Infrastructure, Inc. (C1240); Facility Name: TeraWatt Infrastructure, Inc. (F00650); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 8/14/2023 | None | Electricity | TeraWatt Infrastructure, Inc. (C1240) | TeraWatt Infrastructure, Inc. (F00650) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| B042201 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220100 | -416.31 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| B042202 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220200 | -429.59 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| B042203 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220300 | -249.95 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| B042204 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220400 | -260.14 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| B042205 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220500 | -411.49 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| B042206 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220600 | -418.96 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B042207 | Tier 2 | 3.0 | Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04220700 | -328.54 | 9/14/2023 | Application Package | Bio-CNG | Merced Pipeline LLC (C1199) | Merced Pipeline, LLC (F00518) | Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional) | None | |
| A051001 | Tier 1 | 3.0 | Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: NOBLE ROAD RNG LLC (72142); Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (PROV3.0) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | None | None | CNG025A05100100 | 48.84 | 8/31/2023 | None | Bio-CNG | TRUSTAR ENERGY LLC (6523) | NOBLE ROAD RNG LLC (72142) | Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (Provisional) | None | |
| B047701 | Tier 2 | 3.0 | Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0) | Wyoming | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04770100 | 69.78 | 9/28/2023 | Application Package | Renewable Diesel | Cheyenne Renewable Diesel Company LLC (1647) | Cheyenne Renewable Diesel Company LLC (F00494) | Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional) | None | |
| B047702 | Tier 2 | 3.0 | Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0) | Wyoming | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04770200 | 69.41 | 9/28/2023 | Application Package | Renewable Diesel | Cheyenne Renewable Diesel Company LLC (1647) | Cheyenne Renewable Diesel Company LLC (F00494) | Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional) | None | |
| B047703 | Tier 2 | 3.0 | Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0) | Wyoming | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04770300 | 44.56 | 9/28/2023 | Application Package | Renewable Diesel | Cheyenne Renewable Diesel Company LLC (1647) | Cheyenne Renewable Diesel Company LLC (F00494) | Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional) | None | |
| L022201 | Lookup Table | 3.0 | Fuel Producer: VERDANT ENERGY SERVICES LLC (C1048) ; Facility Name: Verdant Energy Services 0CI (F00661); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/26/2023 | None | Electricity | VERDANT ENERGY SERVICES LLC (C1048) | Verdant Energy Services 0CI (F00661) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L022101 | Lookup Table | 3.0 | Fuel Producer: Republic Services Procurement, Inc. (C1239); Facility Name: Republic Services Procurement, Inc. (F00660); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/22/2023 | None | Electricity | Republic Services Procurement, Inc. (C1239) | Republic Services Procurement, Inc. (F00660) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| L022601 | Lookup Table | 3.0 | Fuel Producer: Neutron Holdings, Inc. (dba Lime) (C1014); Facility Name: Neutron Holdings, Inc. (dba Lime) (F00036); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0) | California | Zero-CI Sources (037) | Electricity (ELC) | None | None | ELC037L00072019 | 0.00 | 9/28/2023 | None | Electricity | Neutron Holdings, Inc. (dba Lime) (C1014) | Neutron Holdings, Inc. (dba Lime) (F00036) | Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California | None | |
| B044901 | Tier 2 | 3.0 | Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use. (3.0) | California | Any Sugar Feedstock (040) | Ethanol (ETH) | ETHWB201 | 69.82 | ETH040B04490100 | 126.33 | 10/2/2023 | Application Package | Ethanol | USL Parallel Products of California (4018) | USL Parallel Products of California (70122) | Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use. | None | |
| A051601 | Tier 1 | 3.0 | Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05160100 | 70.52 | 10/18/2023 | None | Ethanol | Granite Falls Energy, LLC (4769) | Granite Falls Energy, LLC (70071) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional) | None | |
| A051602 | Tier 1 | 3.0 | Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05160200 | 69.50 | 10/18/2023 | None | Ethanol | Granite Falls Energy, LLC (4769) | Granite Falls Energy, LLC (70071) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional) | None | |
| A051603 | Tier 1 | 3.0 | Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05160300 | 23.39 | 10/18/2023 | None | Ethanol - Cellulosic | Granite Falls Energy, LLC (4769) | Granite Falls Energy, LLC (70071) | Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A052901 | Tier 1 | 3.0 | Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05290100 | 41.63 | 10/10/2023 | None | Ethanol - Cellulosic | Chief Ethanol Fuels, Inc (5110) | CHIEF ETHANOL FUELS INC (70150) | Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional) | None | |
| A052902 | Tier 1 | 3.0 | Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A05290200 | 80.80 | 10/10/2023 | None | Ethanol | Chief Ethanol Fuels, Inc (5110) | CHIEF ETHANOL FUELS INC (70150) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional) | None | |
| A052903 | Tier 1 | 3.0 | Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A05290300 | 100.10 | 10/10/2023 | None | Ethanol | Chief Ethanol Fuels, Inc (5110) | CHIEF ETHANOL FUELS INC (70150) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional) | None | |
| A051901 | Tier 1 | 3.0 | Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05190100 | 72.01 | 10/18/2023 | None | Ethanol | Heron Lake BioEnergy (4015) | Heron Lake BioEnergy (70097) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional) | None | |
| A051902 | Tier 1 | 3.0 | Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05190200 | 70.62 | 10/18/2023 | None | Ethanol | Heron Lake BioEnergy (4015) | Heron Lake BioEnergy (70097) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional) | None | |
| A051903 | Tier 1 | 3.0 | Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (PROV3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05190300 | 27.90 | 10/18/2023 | None | Ethanol - Cellulosic | Heron Lake BioEnergy (4015) | Heron Lake BioEnergy (70097) | Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (Provisional) | None | |
| A052001 | Tier 1 | 3.0 | Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00380100 | 77.4 | ETH009A05200100 | 77.86 | 10/30/2023 | None | Ethanol | Chief Ethanol Fuels, Inc (5110) | CHIEF ETHANOL FUELS INC (70241) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (Provisional) | None | |
| A052002 | Tier 1 | 3.0 | Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05200200 | 38.12 | 10/30/2023 | None | Ethanol - Cellulosic | Chief Ethanol Fuels, Inc (5110) | CHIEF ETHANOL FUELS INC (70241) | Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (Provisional) | None | |
| A052101 | Tier 1 | 3.0 | Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A05210100 | 75.51 | 10/31/2023 | None | Ethanol | Green Plains Central City, LLC (3368) | Green Plains Central City LLC (70141) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional) | None | |
| A052102 | Tier 1 | 3.0 | Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A02960100 | 65.97 | ETH009A05210200 | 64.86 | 10/31/2023 | None | Ethanol | Green Plains Central City, LLC (3368) | Green Plains Central City LLC (70141) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional) | None | |
| B045801 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04580100 | 27.39 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B045802 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04580200 | 33.70 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B045803 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04580300 | 47.95 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B045804 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04580400 | 41.15 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B045806 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04580600 | 43.66 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker | None | |
| B045807 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04580700 | 27.61 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t | None | |
| B045808 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04580800 | 33.92 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea | None | |
| B045809 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04580900 | 41.36 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California | None | |
| B045810 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04581000 | 48.17 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California | None | |
| B045811 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04581100 | 43.87 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr | None | |
| B045813 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04581300 | 27.61 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank | None | |
| B045814 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04581400 | 33.92 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t | None | |
| B045815 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04581500 | 48.17 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by | None | |
| B045816 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04581600 | 41.36 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B045817 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04581700 | 43.87 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans | None | |
| B045819 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04581900 | 29.42 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean | None | |
| B045820 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04582000 | 35.72 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc | None | |
| B045821 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04582100 | 49.97 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ | None | |
| B045822 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04582200 | 43.17 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi | None | |
| B045824 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; (3.0) | Finland | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04582400 | 45.68 | 11/9/2023 | Application Package | Renewable Diesel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; | None | |
| B045825 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04582500 | 29.42 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta | None | |
| B045826 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean (3.0) | Finland | Used Cooking Oil/Waste Oil (UCO) (001) | Alternative Jet Fuel (AJF) | None | None | AJF001B04582600 | 35.72 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean | None | |
| B045827 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04582700 | 43.17 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b | None | |
| B045828 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04582800 | 49.97 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b | None | |
| B045829 | Tier 2 | 3.0 | Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra (3.0) | Finland | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | None | None | AJF002B04582900 | 45.68 | 11/9/2023 | Application Package | Alternative Jet Fuel | Neste Oyj (3734) | Neste Renewable Fuels - Porvoo (80272) | European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra | None | |
| A052301 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05230100 | 73.75 | 11/6/2023 | None | Ethanol | POET BIOREFINING - ARTHUR (1578) | Poet Biorefining - Arthur (71682) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A052302 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05230200 | 70.13 | 11/6/2023 | None | Ethanol | POET BIOREFINING - ARTHUR (1578) | Poet Biorefining - Arthur (71682) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052303 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05230300 | 66.14 | 11/6/2023 | None | Ethanol | POET BIOREFINING - ARTHUR (1578) | Poet Biorefining - Arthur (71682) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052304 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05230400 | 26.37 | 11/6/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - ARTHUR (1578) | Poet Biorefining - Arthur (71682) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A053101 | Tier 1 | 3.0 | Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (PROV3.0) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05310100 | 29.36 | 11/6/2023 | None | Ethanol - Cellulosic | Redfield Energy, LLC (4061) | Redfield Energy, LLC (70111) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (Provisional) | None | |
| A053102 | Tier 1 | 3.0 | Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (PROV3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A01450102 | 68.61 | ETH009A05310200 | 67.95 | 11/6/2023 | None | Ethanol | Redfield Energy, LLC (4061) | Redfield Energy, LLC (70111) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (Provisional) | None | |
| A052201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05220100 | 73.95 | 11/17/2023 | None | Ethanol | Poet Biorefining - Shell Rock, LLC (1584) | Poet Biorefining - Shell Rock (71686) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05220200 | 69.64 | 11/17/2023 | None | Ethanol | Poet Biorefining - Shell Rock, LLC (1584) | Poet Biorefining - Shell Rock (71686) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05220300 | 65.44 | 11/17/2023 | None | Ethanol | Poet Biorefining - Shell Rock, LLC (1584) | Poet Biorefining - Shell Rock (71686) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052204 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05220400 | 26.04 | 11/17/2023 | None | Ethanol - Cellulosic | Poet Biorefining - Shell Rock, LLC (1584) | Poet Biorefining - Shell Rock (71686) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052501 | Tier 1 | 3.0 | Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0) | Texas | Corn (009) | Ethanol (ETH) | ETHC248L | 67.6 | ETH009A05250100 | 65.34 | 11/16/2023 | None | Ethanol | HEREFORD ETHANOL PARTNERS, LP (1501) | HEREFORD ETHANOL PARTNERS, LP (21601 | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional) | None | |
| A052502 | Tier 1 | 3.0 | Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0) | Texas | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A05250200 | 66.44 | 11/16/2023 | None | Ethanol | HEREFORD ETHANOL PARTNERS, LP (1501) | HEREFORD ETHANOL PARTNERS, LP (21601 | Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (Provisional) | None | |
| A052503 | Tier 1 | 3.0 | Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (PROV3.0) | Texas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05250300 | 26.15 | 11/16/2023 | None | Ethanol - Cellulosic | HEREFORD ETHANOL PARTNERS, LP (1501) | HEREFORD ETHANOL PARTNERS, LP (21601 | Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A052701 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05270100 | 71.98 | 11/17/2023 | None | Ethanol | POET BIOREFINING - MENLO (1583) | MENLO (71685) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052702 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05270200 | 68.33 | 11/17/2023 | None | Ethanol | POET BIOREFINING - MENLO (1583) | MENLO (71685) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052703 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05270300 | 64.40 | 11/17/2023 | None | Ethanol | POET BIOREFINING - MENLO (1583) | MENLO (71685) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052704 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05270400 | 25.02 | 11/17/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - MENLO (1583) | MENLO (71685) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A053301 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05330100 | 72.65 | 11/17/2023 | None | Ethanol | POET BIOPROCESSING FAIRBANK (1581) | FAIRBANK (71683) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A053302 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05330200 | 69.00 | 11/17/2023 | None | Ethanol | POET BIOPROCESSING FAIRBANK (1581) | FAIRBANK (71683) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A053303 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05330300 | 64.38 | 11/17/2023 | None | Ethanol | POET BIOPROCESSING FAIRBANK (1581) | FAIRBANK (71683) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A053304 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05330400 | 24.65 | 11/17/2023 | None | Ethanol - Cellulosic | POET BIOPROCESSING FAIRBANK (1581) | FAIRBANK (71683) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052801 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05280100 | 72.60 | 11/28/2023 | None | Ethanol | POET BIOPROCESSING IOWA FALLS (1582) | IOWA FALLS (71684) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052802 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05280200 | 70.11 | 11/28/2023 | None | Ethanol | POET BIOPROCESSING IOWA FALLS (1582) | IOWA FALLS (71684) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052803 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05280300 | 64.89 | 11/28/2023 | None | Ethanol | POET BIOPROCESSING IOWA FALLS (1582) | IOWA FALLS (71684) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional) | None | |
| A052804 | Tier 1 | 3.0 | Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05280400 | 24.29 | 11/28/2023 | None | Ethanol - Cellulosic | POET BIOPROCESSING IOWA FALLS (1582) | IOWA FALLS (71684) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B047301 | Tier 2 | 3.0 | Fuel Producer: SUNOMA RENEWABLE BIOFUEL, LLC (1781); Facility Name: Sunoma Renewable Biofuel, LLC (F00497); Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (PROV3.0) | Arizona | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04730100 | -386.78 | 12/4/2023 | Application Package | Bio-CNG | SUNOMA RENEWABLE BIOFUEL, LLC (1781) | Sunoma Renewable Biofuel, LLC (F00497) | Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (Provisional) | None | |
| B048201 | Tier 2 | 3.0 | Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail (3.0) | Wyoming | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04820100 | 33.19 | 12/6/2023 | Application Package | Renewable Diesel | Wyoming Renewable Diesel Company LLC (1440) | Wyoming Renewable Diesel Company LLC (82441) | North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail | None | |
| B049201 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Canola Oil (006) | Renewable Diesel (RND) | None | None | RND006B04920100 | 54.20 | 12/6/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049202 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B04920200 | 28.60 | 12/6/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049203 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B04920300 | 58.00 | 12/6/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049204 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04920400 | 33.20 | 12/6/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049205 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B04920500 | 20.70 | 12/6/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049206 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Canola Oil (006) | Renewable Naphtha (RNT) | None | None | RNT006B04920600 | 54.20 | 12/6/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049207 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | None | None | RNT003B04920700 | 28.60 | 12/6/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049208 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Soybean Oil (005) | Renewable Naphtha (RNT) | None | None | RNT005B04920800 | 58.00 | 12/6/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049209 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B04920900 | 33.20 | 12/6/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |
| B049210 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0) | Texas | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B04921000 | 20.70 | 12/6/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | DIAMOND GREEN DIESEL - PORT ARTHUR (82621) | North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B049501 | Tier 2 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (PROV3.0) | Mississippi | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B04950100 | 63.29 | 12/18/2023 | Application Package | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (Provisional) | None | |
| A052601 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A05120200 | 72.75 | ETH009A05260100 | 71.72 | 12/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional) | None | |
| A052602 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A05120100 | 63.8 | ETH009A05260200 | 64.93 | 12/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional) | None | |
| A052603 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0) | Kansas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05260300 | 24.31 | 12/8/2023 | None | Ethanol - Cellulosic | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional) | None | |
| A052604 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A05120400 | 74.66 | ETH010A05260400 | 74.26 | 12/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional) | None | |
| A052605 | Tier 1 | 3.0 | Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A05120300 | 65.71 | ETH010A05260500 | 67.47 | 12/8/2023 | None | Ethanol | Arkalon Ethanol, LLC (5715) | Arkalon Ethanol, LLC (70247) | Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional) | None | |
| B042401 | Tier 2 | 3.0 | Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: North Las Vegas Liquid Hydrogen Plant (F00371); Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (PROV3.0) | Nevada | North American NG | Liquid Hydrogen (HYL) | None | None | HYL031B04240100 | 188.60 | 12/21/2023 | Application Package | Hydrogen | Air Liquide Hydrogen Energy US LLC (A491) | North Las Vegas Liquid Hydrogen Plant (F00371) | Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (Provisional) | None | |
| B050101 | Tier 2 | 3.0 | Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0) | New Mexico | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B05010100 | 57.67 | 12/20/2023 | Application Package | Renewable Diesel | ARTESIA RENEWABLE DIESEL COMPANY LLC (1646) | RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381) | U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional) | None | |
| B050102 | Tier 2 | 3.0 | Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0) | New Mexico | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B05010200 | 30.05 | 12/20/2023 | Application Package | Renewable Diesel | ARTESIA RENEWABLE DIESEL COMPANY LLC (1646) | RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381) | U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional) | None | |
| B050103 | Tier 2 | 3.0 | Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0) | New Mexico | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05010300 | 34.05 | 12/20/2023 | Application Package | Renewable Diesel | ARTESIA RENEWABLE DIESEL COMPANY LLC (1646) | RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381) | U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional) | None | |
| B046101 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04610100 | -130.23 | 12/28/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | HOLSUM RNG PROJECT (71481) | Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional) | None | |
| B046102 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04610200 | -385.43 | 12/28/2023 | Application Package | Bio-CNG | U.S. Venture, Inc. (5504) | HOLSUM RNG PROJECT (71481) | Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B045901 | Tier 2 | 3.0 | Fuel Producer: Still Water Power, LLC (C1180); Facility Name: Still Water Power, LLC (F00552); Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B04590100 | -332.64 | 12/29/2023 | Application Package | Bio-CNG | Still Water Power, LLC (C1180) | Still Water Power, LLC (F00552) | Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use | None | |
| B049001 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: Bar 20 Biogas LLC (F00510); Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (PROV3.0) | California | Dairy Manure (026) | Electricity (ELC) | None | None | ELC026B04900100 | -790.41 | 12/28/2023 | Application Package | Electricity | California Bioenergy LLC (B194) | Bar 20 Biogas LLC (F00510) | Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (Provisional) | None | |
| B049401 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (PROV3.0) | Nevada | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04940100 | -158.06 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (Provisional) | None | |
| B049402 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (PROV3.0) | Nevada | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04940200 | -181.75 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (Provisional) | None | |
| B049403 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (PROV3.0) | Nevada | Dairy Manure (026) | Liquid Hydrogen (HYL) | None | None | HYL026B04940300 | -119.24 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (Provisional) | None | |
| B049404 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (PROV3.0) | Nevada | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04940400 | -141.61 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (Provisional) | None | |
| B049405 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (PROV3.0) | Nevada | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04940500 | -165.30 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (Provisional) | None | |
| B049406 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (PROV3.0) | Nevada | Dairy Manure (026) | Gaseous Hydrogen (HYG) | None | None | HYG026B04940600 | -102.79 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (Provisional) | None | |
| B049407 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (PROV3.0) | Nevada | North American Fossil NG (031) | Gaseous Hydrogen (HYG) | None | None | HYG031B04940700 | 205.05 | 12/29/2023 | Application Package | Hydrogen | FirstElement Fuel (E426) | AL North Las Vegas Liquid Hydrogen Plant (F00523) | Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (Provisional) | None | |
| B050601 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0) | California | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B05060100 | 62.93 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional) | None | |
| B050602 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0) | California | Canola Oil (006) | Renewable Diesel (RND) | None | None | RND006B05060200 | 56.54 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional) | None | |
| B050603 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0) | California | Distillers' Corn Oil (003) | Renewable Diesel (RND) | None | None | RND003B05060300 | 35.24 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B050604 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B05060400 | 29.22 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional) | None | |
| B050605 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05060500 | 37.14 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional) | None | |
| B050606 | Tier 2 | 3.0 | Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05060600 | 46.40 | 12/26/2023 | Application Package | Renewable Diesel | MARTINEZ RENEWABLES LLC (1845) | MARTINEZ REFINERY (90001) | Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional) | None | |
| B051401 | Tier 2 | 3.0 | Fuel Producer: FM Jerseys Dairy Biogas, LLC (C1178); Facility Name: FM Jerseys Dairy Digester (F00479); Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | None | None | CNG026B05140100 | -426.46 | 12/28/2023 | Application Package | Bio-CNG | FM Jerseys Dairy Biogas, LLC (C1178) | FM Jerseys Dairy Digester (F00479) | Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use | None | |
| B052001 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge (3.0) | California | Soybean Oil (005) | Renewable Diesel (RND) | None | None | RND005B05200100 | 61.98 | 12/26/2023 | Application Package | Renewable Diesel | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge | None | |
| B054001 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0) | Louisiana | Canola Oil (006) | Renewable Diesel (RND) | None | None | RND006B05400100 | 55.11 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker | None | |
| B054002 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B05400200 | 29.76 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054003 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05400300 | 46.07 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054004 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05400400 | 37.24 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054005 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | None | None | RND001B05400500 | 39.77 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054006 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | None | None | RND002B05400600 | 46.43 | 12/29/2023 | Application Package | Renewable Diesel | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054007 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0) | Louisiana | Canola Oil (006) | Renewable Naphtha (RNT) | None | None | RNT006B05400700 | 55.11 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B054008 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B05400800 | 29.76 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054009 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B05400900 | 46.07 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054010 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B05401000 | 37.24 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054011 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | None | None | RNT001B05401100 | 39.77 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| B054012 | Tier 2 | 3.0 | Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | None | None | RNT002B05401200 | 46.43 | 12/29/2023 | Application Package | Renewable Naphtha | Diamond Green Diesel Holdings LLC (6072) | Diamond Green Diesel LLC (81496) | Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker | None | |
| A005001 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0) | Missouri | Corn (009) | Ethanol (ETH) | ETH009A00500102 | 71.21 | ETH009A00500103 | 70.13 | 10/17/2023 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport | 2022 AFPR Recert Complete | |
| A005002 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0) | Missouri | Corn (009) | Ethanol (ETH) | ETH009A00500202 | 63.83 | ETH009A00500203 | 63.10 | 10/17/2023 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport | 2022 AFPR Recert Complete | |
| A005003 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0) | Missouri | Corn (009) | Ethanol (ETH) | ETH012A00500302 | 23.97 | ETH012A00500303 | 23.19 | 10/17/2023 | None | Ethanol | POET Biorefining - Laddonia (4787) | POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport | 2022 AFPR Recert Complete | |
| A005101 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00510102 | 70.77 | ETH009A00510103 | 69.15 | 11/7/2023 | None | Ethanol | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005102 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00510202 | 30.54 | ETH012A00510203 | 29.19 | 11/7/2023 | None | Ethanol - Cellulosic | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00520103 | 74.36 | ETH009A00520104 | 75.43 | 11/6/2023 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00520203 | 66.04 | ETH009A00520204 | 66.02 | 11/6/2023 | None | Ethanol | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A005203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00520303 | 26.29 | ETH012A00520304 | 26.30 | 11/6/2023 | None | Ethanol - Cellulosic | Poet Biorefining Hanlontown (4785) | Poet Biorefining Hanlontown (70010) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005301 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00530103 | 72.85 | ETH009A00530104 | 73.25 | 10/20/2023 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005302 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00530203 | 65.95 | ETH009A00530204 | 66.39 | 10/20/2023 | None | Ethanol | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005303 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00530303 | 25.98 | ETH012A00530304 | 26.35 | 10/20/2023 | None | Ethanol - Cellulosic | Poet Biorefining Jewell (4786) | Poet Biorefining Jewell (70014) | Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005501 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00550101 | 77.66 | ETH009A00550102 | 77.57 | 10/17/2023 | None | Ethanol | POET Biorefining - Glenville (4779) | POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020) | Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005502 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00550201 | 69.88 | ETH009A00550202 | 69.86 | 10/17/2023 | None | Ethanol | POET Biorefining - Glenville (4779) | POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020) | Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005503 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020);  Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00550301 | 29.92 | ETH012A00550302 | 30.11 | 10/17/2023 | None | Ethanol - Cellulosic | POET Biorefining - Glenville (4779) | POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020) |  Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005601 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00560102 | 73.89 | ETH009A00560103 | 73.50 | 10/23/2023 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005602 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00560202 | 67.49 | ETH009A00560203 | 66.85 | 10/23/2023 | None | Ethanol | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005603 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00560302 | 28.27 | ETH012A00560303 | 27.47 | 10/23/2023 | None | Ethanol - Cellulosic | POET Biorefining - Coon Rapids (4783) | POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005801 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00580102 | 73.74 | ETH009A00580103 | 78.77 | 10/23/2023 | None | Ethanol | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A005802 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A00580202 | 68.00 | ETH009A00580203 | 68.77 | 10/23/2023 | None | Ethanol | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A005803 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00580302 | 28.21 | ETH012A00580303 | 29.07 | 10/23/2023 | None | Ethanol - Cellulosic | POET Biorefining - Bingham Lake (4780) | POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006001 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00600102 | 76.01 | ETH009A00600103 | 74.07 | 10/17/2023 | None | Ethanol | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006002 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00600202 | 66.53 | ETH009A00600203 | 64.20 | 10/17/2023 | None | Ethanol | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006003 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00600302 | 26.40 | ETH012A00600303 | 24.45 | 10/17/2023 | None | Ethanol - Cellulosic | Poet Biorefining Emmetsburg (4792) | Poet Biorefining Emmetsburg (70021) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006101 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00610102 | 75.21 | ETH009A00610103 | 74.60 | 10/23/2023 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006102 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00610202 | 65.67 | ETH009A00610203 | 64.82 | 10/23/2023 | None | Ethanol | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006103 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00610302 | 26.04 | ETH012A00610303 | 25.35 | 10/23/2023 | None | Ethanol - Cellulosic | Poet Biorefining Hudson (4791) | Poet Biorefining Hudson (70022) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006201 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00620101 | 74.47 | ETH009A00620102 | 73.69 | 10/17/2023 | None | Ethanol | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006202 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A00620201 | 67.18 | ETH009A00620202 | 65.82 | 10/17/2023 | None | Ethanol | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006203 | Tier 1 | 3.0 | Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A00620301 | 27.03 | ETH012A00620302 | 25.91 | 10/17/2023 | None | Ethanol - Cellulosic | Poet Biorefining Mitchell (4789) | Poet Biorefining Mitchell (70016) | Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006401 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00640102 | 72.37 | ETH009A00640103 | 72.70 | 11/7/2023 | None | Ethanol | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A006402 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A00640202 | 64.75 | ETH009A00640203 | 64.56 | 11/7/2023 | None | Ethanol | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A006403 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A00640302 | 24.60 | ETH012A00640303 | 24.25 | 11/7/2023 | None | Ethanol - Cellulosic | POET Biorefining - Gowrie (4784) | POET Biorefining - Gowrie (70033) | Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A008301 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Soybean Oil (005) | Biodiesel (BIO) | BIO005A00830100 | 53.68 | BIO005A00830102 | 54.50 | 12/4/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | 2022 AFPR Recert Complete | |
| A008302 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Canola Oil (006) | Biodiesel (BIO) | BIO006A00830200 | 48.49 | BIO006A00830201 | 49.00 | 12/4/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | 2022 AFPR Recert Complete | |
| A008304 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A00830401 | 18.00 | BIO001A00830402 | 18.00 | 12/6/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | 2022 AFPR Recert Complete | |
| A008305 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A00830501 | 13.00 | BIO001A00830502 | 13.00 | 12/6/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | 2022 AFPR Recert Complete | |
| A008306 | Tier 1 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0) | Minnesota | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A00830601 | 29.25 | BIO002A00830602 | 29.25 | 12/6/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California | 2022 AFPR Recert Complete | |
| A008601 | Tier 1 | 3.0 | Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A00860101 | 63.00 | ETH009A00860102 | 63.66 | 11/7/2023 | None | Ethanol | Bridgeport Ethanol, LLC 5934 | Bridgeport Ethanol, LLC 70217 | Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A008801 | Tier 1 | 3.0 | Fuel Producer: Yuma Ethanol, LLC (4735); Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California (3.0) | Colorado | Corn (009) | Ethanol (ETH) | ETH009A00880101 | 64.00 | ETH009A00880102 | 63.52 | 11/7/2023 | None | Ethanol | Yuma Ethanol, LLC (4735) | Yuma Ethanol, LLC (70024) | Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A010001 | Tier 1 | 3.0 | Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01000100 | 71.62 | ETH009A01000101 | 72.26 | 11/7/2023 | None | Ethanol | The Andersons Marathon Holdings LLC (1143) | DENISON ETHANOL PLANT (70884) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | 2022 AFPR Recert Complete | |
| A010002 | Tier 1 | 3.0 | Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A01000201 | 67.11 | ETH009A01000202 | 67.12 | 11/7/2023 | None | Ethanol | The Andersons Marathon Holdings LLC (1143) | DENISON ETHANOL PLANT (70884) | Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California | 2022 AFPR Recert Complete | |
| A009501 | Tier 1 | 3.0 | Fuel Producer: CEFARI RNG OKC, LLC (2220); Facility Name: CEFARI RNG OKC, LLC (70101); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (3.0) | Oklahoma | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A00950101 | 49.80 | CNG025A00950102 | 52.00 | 11/14/2023 | None | Bio-CNG | CEFARI RNG OKC, LLC (2220) | CEFARI RNG OKC, LLC (70101) | Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California | 2022 AFPR Recert Complete | |
| A010501 | Tier 1 | 3.0 | Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker (3.0) | South Korea | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A01050101 | 25.00 | BIO001A01050102 | 25.28 | 11/6/2023 | None | Biodiesel | Dansuk Industrial Co., Ltd (5953) | Pyeongtaek 2 (80202) | South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A011001 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (3.0) | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01100101 | 48.21 | CNG025A01100102 | 46.33 | 11/6/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Ameresco Woodland Meadows Romulus, LLC (A0833) | Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California | 2022 AFPR Recert Complete | |
| A011501 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0) | Texas | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A01150101 | 36.77 | CNG030A01150102 | 36.73 | 11/3/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Ameresco San Antonio Biogas (71204) | Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | 2022 AFPR Recert Complete | |
| B001901 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00190100 | -352.89 | ELC026B00190101 | -364.41 | 11/13/2023 | None | Electricity | CleanFuture, Inc. (C1001) | Open Sky (F00007) | Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California | 2022 AFPR Recert Complete | |
| A012701 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN;  Ethanol transported by rail to California (3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A01270103 | 28.29 | ETH012A01270104 | 27.92 | 11/7/2023 | None | Ethanol - Cellulosic | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN;  Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012702 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01270203 | 77.34 | ETH009A01270204 | 77.70 | 11/7/2023 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012703 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01270303 | 68.22 | ETH009A01270304 | 67.61 | 11/7/2023 | None | Ethanol | POET Biorefining - Preston (4790) | POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012801 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01280102 | 75.31 | ETH009A01280103 | 75.28 | 10/17/2023 | None | Ethanol | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012802 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A01280202 | 68.32 | ETH009A01280203 | 67.59 | 10/17/2023 | None | Ethanol | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012803 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A01280302 | 28.66 | ETH012A01280303 | 28.18 | 10/17/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) | POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012901 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01290101 | 73.48 | ETH009A01290102 | 73.58 | 11/7/2023 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012902 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01290201 | 66.73 | ETH009A01290202 | 67.04 | 11/7/2023 | None | Ethanol | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A012903 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A01290301 | 27.01 | ETH012A01290302 | 27.13 | 11/7/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728) | POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A013001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01300101 | 72.10 | ETH009A01300102 | 72.00 | 11/7/2023 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A013002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01300201 | 65.09 | ETH009A01300202 | 64.54 | 11/7/2023 | None | Ethanol | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A013003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01300301 | 25.09 | ETH012A01300302 | 24.63 | 11/7/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513) | POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A013102 | Tier 1 | 3.0 | Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California (3.0) | Iowa | Canola Oil (006) | Biodiesel (BIO) | BIO006A01310202 | 50.11 | BIO006A01310203 | 50.75 | 10/30/2023 | None | Biodiesel | REG Mason City, LLC (6130) | REG Mason City, LLC (82968) | U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California | 2022 AFPR Recert Complete | |
| A013501 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0) | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A01350102 | 31.65 | BIO002A01350103 | 31.65 | 12/11/2023 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | 2022 AFPR Recert Complete | |
| A013502 | Tier 1 | 3.0 | Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0) | Oklahoma | Soybean Oil (005) | Biodiesel (BIO) | BIO005A01350200 | 55.82 | BIO005A01350201 | 55.82 | 12/11/2023 | None | Biodiesel | High Plains Bioenergy (4846) | High Plains Bioenergy (82883) | Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | 2022 AFPR Recert Complete | |
| A013503 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0) | Oklahoma | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A01350300 | 20.68 | BIO001A01350301 | 20.68 | 12/11/2023 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California | 2022 AFPR Recert Complete | |
| A013901 | Tier 1 | 3.0 | Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A01390102 | 65.76 | ETH009A01390103 | 65.20 | 12/21/2023 | None | Ethanol | Midwest Renewable Energy (5214) | Midwest Renewable Energy (70160) | Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A014101 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0) | Missouri | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003A01410102 | 27.16 | BIO003A01410103 | 27.78 | 10/31/2023 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441) | Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | 2022 AFPR Recert Complete | |
| A014102 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0) | Missouri | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A01410202 | 32.08 | BIO002A01410203 | 31.88 | 10/31/2023 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441) | Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California | 2022 AFPR Recert Complete | |
| A014601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0) | Michigan | Corn (009) | Ethanol (ETH) | ETH009A01460101 | 72.29 | ETH009A01460102 | 72.48 | 10/23/2023 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | 2022 AFPR Recert Complete | |
| A014602 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0) | Michigan | Corn (009) | Ethanol (ETH) | ETH009A01460201 | 66.61 | ETH009A01460202 | 66.75 | 10/23/2023 | None | Ethanol | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A014603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (3.0) | Michigan | Corn Fiber (012) | Ethanol (ETH) | ETH012A01460301 | 27.03 | ETH012A01460302 | 27.27 | 10/23/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781) | POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California | 2022 AFPR Recert Complete | |
| A015001 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01500101 | 74.03 | ETH009A01500102 | 73.74 | 11/13/2023 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015002 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01500201 | 67.28 | ETH009A01500202 | 66.96 | 11/13/2023 | None | Ethanol | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015003 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01500301 | 27.19 | ETH012A01500302 | 26.95 | 11/13/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) | POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015101 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01510101 | 73.56 | ETH009A01510102 | 73.60 | 10/23/2023 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California | 2022 AFPR Recert Complete | |
| A015103 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A01510301 | 26.17 | ETH012A01510302 | 26.30 | 10/23/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01520101 | 72.75 | ETH009A01520102 | 72.34 | 11/13/2023 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A01520201 | 65.82 | ETH009A01520202 | 65.13 | 11/13/2023 | None | Ethanol | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0) | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A01520301 | 25.89 | ETH012A01520302 | 26.01 | 11/13/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518) | POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015401 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (3.0) | Kentucky | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01540102 | 54.69 | CNG025A01540103 | 55.00 | 12/11/2023 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California | 2022 AFPR Recert Complete | |
| A015402 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (3.0) | Kentucky | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A01540202 | 72.09 | LNG025A01540203 | 73.15 | 12/11/2023 | None | Bio-LNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations | 2022 AFPR Recert Complete | |
| A015403 | Tier 1 | 3.0 | Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (3.0) | Kentucky | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A01540302 | 75.18 | LCN025A01540303 | 76.24 | 12/11/2023 | None | Bio-CNG | WM Renewable Energy, LLC (W978) | Outer Loop High Btu Gas Plant (71316) | Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A015102 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A01510201 | 66.14 | ETH009A01510202 | 66.24 | 10/23/2023 | None | Ethanol | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) | POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A015601 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (3.0) | Arizona | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A01560100 | 26.58 | CNG030A01560101 | 25.35 | 10/27/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel | 2022 AFPR Recert Complete | |
| A016901 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (3.0) | Arizona | Wastewater Sludge (030) | Liquefied Natural Gas (LNG) | LNG030A01690100 | 41.58 | LNG030A01690101 | 42.61 | 11/20/2023 | None | Bio-LNG | Anew RNG, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. | 2022 AFPR Recert Complete | |
| A016902 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (3.0) | Arizona | Wastewater Sludge (030) | Liquefied Compressed Natural Gas (LCN) | LCN030A01690200 | 44.67 | LCN030A01690201 | 45.70 | 11/20/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Ninety-First Avenue Renewable Biogas LLC (70241) | Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as | 2022 AFPR Recert Complete | |
| A017101 | Tier 1 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California (3.0) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026A01710100 | -329.76 | CNG026A01710101 | -185.00 | 10/25/2023 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Fair Oaks Upgrader, LLC (71001) | Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California | 2022 AFPR Recert Complete | |
| A017401 | Tier 1 | 3.0 | Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A01740100 | 65.77 | ETH009A01740101 | 65.55 | 10/17/2023 | None | Ethanol | Nebraska Corn Processing (3516) | Nebraska Corn Processing LLC (70230) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A019501 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A01950101 | 44.78 | CNG025A01950102 | 46.75 | 11/6/2023 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060) | Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel | 2022 AFPR Recert Complete | |
| B005901 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. (3.0) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00590102 | -568.21 | ELC026B00590103 | -613.23 | 11/14/2023 | None | Electricity | California Bioenergy LLC (B194) | ABEC Bidart-Old River LLC (F00113) | Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. | 2022 AFPR Recert Complete | |
| A020001 | Tier 1 | 3.0 | Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (3.0) | Ohio | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02000101 | 37.64 | CNG025A02000102 | 37.59 | 11/6/2023 | None | Bio-CNG | GHI Energy, LLC (6156) | Waste Management American Landfill (70421) | Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. | 2022 AFPR Recert Complete | |
| A020101 | Tier 1 | 3.0 | Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail (3.0) | Michigan | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02010100 | 15.80 | BIO001A02010101 | 15.14 | 10/31/2023 | None | Biodiesel | Thumb BioEnergy (3862) | Thumb BioEnergy (03862) | Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail | 2022 AFPR Recert Complete | |
| A020701 | Tier 1 | 3.0 | Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (3.0) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02070100 | 38.07 | CNG025A02070101 | 36.38 | 11/17/2023 | None | Bio-CNG | MEM RNG, LLC (2141) | Blue Ridge Landfill, LLC (F00132) | Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel | 2022 AFPR Recert Complete | |
| A021201 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0) | Missouri | Corn (009) | Ethanol (ETH) | ETH009A02120102 | 75.47 | ETH009A02120103 | 74.18 | 10/24/2023 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A021202 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (3.0) | Missouri | Corn (009) | Ethanol (ETH) | ETH009A02120201 | 64.95 | ETH009A02120202 | 64.00 | 10/24/2023 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A021203 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0) | Missouri | Corn Fiber (012) | Ethanol (ETH) | ETH012A02120301 | 25.32 | ETH012A02120302 | 24.65 | 10/24/2023 | None | Ethanol | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) | POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017) | Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A021301 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02130101 | 61.55 | ETH009A02130102 | 61.85 | 11/13/2023 | None | Ethanol | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI | 2022 AFPR Recert Complete | |
| A021302 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (3.0) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A02130203 | 21.93 | ETH012A02130204 | 22.00 | 11/13/2023 | None | Ethanol - Cellulosic | POET Biorefining - Chancellor, LLC (4727) | POET Biorefining - Chancellor, LLC (70012) | Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| B008002 | Tier 2 | 3.0 | Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (3.0) | California | Other Organic Waste (029) | Electricity (ELC) | ELC029B00800201 | -221.76 | ELC029B00800202 | -346.47 | 12/11/2023 | None | Electricity | Bridge To Renewables, Benefit LLC (C1006) | Blake's Landing Farms (F00019) | Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI | 2022 AFPR Recert Complete | |
| A022401 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02240102 | 73.00 | ETH009A02240103 | 73.85 | 12/12/2023 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A022402 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02240202 | 68.00 | ETH009A02240203 | 67.75 | 12/12/2023 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A022403 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02240301 | 64.13 | ETH009A02240302 | 66.00 | 12/12/2023 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A022404 | Tier 1 | 3.0 | Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A02240402 | 26.00 | ETH012A02240403 | 26.00 | 12/12/2023 | None | Ethanol | LSCP, LLC (4728) | LSCP, LLC (70015) | Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| B009801 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980101 | -401.33 | CNG026B00980102 | -419.92 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| B009802 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980201 | -402.07 | CNG026B00980202 | -418.16 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| B009803 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980300 | -192.49 | CNG026B00980301 | -420.09 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B009804 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980400 | -323.10 | CNG026B00980401 | -419.74 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| B009805 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980501 | -304.08 | CNG026B00980502 | -419.77 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| B009806 | Tier 2 | 3.0 | Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B00980601 | -279.38 | CNG026B00980602 | -227.28 | 10/25/2023 | None | Bio-CNG | Calgren Dairy Fuels, LLC (C1007) | Calgren Dairy Fuels, LLC (F00029) | Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| A023301 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (3.0) | Kansas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02330102 | 47.10 | CNG025A02330103 | 45.13 | 11/17/2023 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| B002401 | Tier 2 | 3.0 | Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California (3.0) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B00240100 | -525.14 | ELC026B00240101 | -760.21 | 11/13/2023 | None | Electricity | CleanFuture, Inc. (C1001) | Coronado Dairy Farm (F00009) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California | 2022 AFPR Recert Complete | |
| A024501 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02450103 | 73.16 | ETH009A02450104 | 73.27 | 10/18/2023 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A024502 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A02450203 | 64.79 | ETH009A02450204 | 65.00 | 10/18/2023 | None | Ethanol | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A024503 | Tier 1 | 3.0 | Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A02450303 | 24.71 | ETH012A02450304 | 25.42 | 10/18/2023 | None | Ethanol - Cellulosic | POET Biorefining - Ashton (4782) | POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A024201 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG (3.0) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02420102 | 57.00 | CNG025A02420104 | 60.50 | 11/28/2023 | None | Bio-CNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A024202 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations (3.0) | Tennessee | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02420201 | 63.35 | LNG025A02420203 | 76.47 | 11/28/2023 | None | Bio-LNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A024203 | Tier 1 | 3.0 | Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0) | Tennessee | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02420301 | 66.44 | LCN025A02420303 | 79.55 | 11/28/2023 | None | Bio-CNG | CERF SHELBY LLC (6228) | CERF SHELBY LLC (71163) | Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| A024601 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A02460101 | 76.22 | ETH009A02460102 | 73.94 | 10/24/2023 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A024602 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn (009) | Ethanol (ETH) | ETH009A02460201 | 68.53 | ETH009A02460202 | 66.40 | 10/24/2023 | None | Ethanol | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A024603 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0) | Ohio | Corn Fiber (012) | Ethanol (ETH) | ETH012A02460302 | 28.47 | ETH012A02460303 | 26.48 | 10/24/2023 | None | Ethanol - Cellulosic | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) | POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327) | Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A024701 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG (3.0) | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02470102 | 48.20 | CNG025A02470104 | 50.00 | 11/28/2023 | None | Bio-CNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A024702 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations (3.0) | Michigan | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02470200 | 62.68 | LNG025A02470201 | 58.89 | 11/28/2023 | None | Bio-LNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A024703 | Tier 1 | 3.0 | Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0) | Michigan | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02470300 | 65.77 | LCN025A02470301 | 61.98 | 11/28/2023 | None | Bio-CNG | CANTON RENEWABLES, LLC (5896) | CANTON RENEWABLES, LLC (71041) | Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| A024901 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02490102 | 76.29 | ETH009A02490103 | 76.56 | 10/24/2023 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | 2022 AFPR Recert Complete | |
| A024902 | Tier 1 | 3.0 | Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A02490201 | 68.82 | ETH009A02490202 | 68.67 | 10/24/2023 | None | Ethanol | Glacial Lakes Corn Processors (4764) | Huron Energy, LLC (70722) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI | 2022 AFPR Recert Complete | |
| A025901 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0) | Tennessee | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003A02590102 | 37.49 | BIO003A02590103 | 36.92 | 11/1/2023 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (83730) | U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California | 2022 AFPR Recert Complete | |
| A025902 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0) | Tennessee | Soybean Oil (005) | Biodiesel (BIO) | BIO005A02590202 | 66.85 | BIO005A02590203 | 67.83 | 11/1/2023 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (83730) | U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California | 2022 AFPR Recert Complete | |
| A025903 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0) | Tennessee | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A02590302 | 42.58 | BIO002A02590303 | 41.61 | 11/1/2023 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (83730) | U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California | 2022 AFPR Recert Complete | |
| A025904 | Tier 1 | 3.0 | Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0) | Tennessee | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02590400 | 31.60 | BIO001A02590401 | 29.54 | 11/1/2023 | None | Biodiesel | Bioenergy Development Group LLC (3785) | Bioenergy Development Group, LLC (83730) | U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California | 2022 AFPR Recert Complete | |
| A027401 | Tier 1 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (3.0) | Texas | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A02740102 | 41.71 | CNG030A02740103 | 41.23 | 10/27/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Renovar Arlington, LTD RNG Project (70501) | Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A027901 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0) | Arkansas | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003A02790101 | 33.53 | BIO003A02790102 | 34.29 | 11/2/2023 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California | 2022 AFPR Recert Complete | |
| A027902 | Tier 1 | 3.0 | Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0) | Arkansas | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02790202 | 26.13 | BIO001A02790203 | 26.62 | 11/2/2023 | None | Biodiesel | FutureFuel Chemical Company (4664) | FutureFuel Chemical Company (82612) | US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California | 2022 AFPR Recert Complete | |
| A028201 | Tier 1 | 3.0 | Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (3.0) | Oklahoma | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A02820102 | 24.60 | BIO002A02820103 | 24.60 | 12/11/2023 | None | Biodiesel | Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846) | Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883) | Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail | 2022 AFPR Recert Complete | |
| A028905 | Tier 1 | 3.0 | Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. (3.0) | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02890500 | 21.50 | BIO001A02890501 | 21.60 | 10/31/2023 | None | Biodiesel | REG Danville, LLC (3723) | REG Danville, LLC (80216) | U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. | 2022 AFPR Recert Complete | |
| A029002 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. (3.0) | Illinois | Soybean Oil (005) | Biodiesel (BIO) | BIO005A02900201 | 58.00 | BIO005A02900202 | 57.50 | 12/4/2023 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. | 2022 AFPR Recert Complete | |
| A029004 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0) | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02900400 | 20.75 | BIO001A02900401 | 21.25 | 11/8/2023 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | 2022 AFPR Recert Complete | |
| A029005 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail (3.0) | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02900500 | 16.25 | BIO001A02900501 | 16.50 | 11/8/2023 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail | 2022 AFPR Recert Complete | |
| A029006 | Tier 1 | 3.0 | Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0) | Illinois | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02900601 | 22.00 | BIO001A02900602 | 23.50 | 12/4/2023 | None | Biodiesel | REG Seneca, LLC (3652) | REG Seneca, LLC (80232) | U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. | 2022 AFPR Recert Complete | |
| B013302 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Distillers' Corn Oil (003) | Renewable Diesel (RND) | RND003B01330200 | 32.50 | RND003B01330202 | 32.50 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B013303 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RND001B01330300 | 25.50 | RND001B01330302 | 25.50 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B013304 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RND001B01330400 | 20.00 | RND001B01330402 | 20.00 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B013305 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Diesel (RND) | RND001B01330500 | 26.00 | RND001B01330502 | 26.00 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B013307 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B01330700 | 37.00 | RND002B01330702 | 37.00 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B013308 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B01330800 | 38.00 | RND002B01330802 | 38.00 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B013309 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B01330900 | 43.00 | RND002B01330902 | 43.00 | 11/20/2023 | None | Renewable Diesel | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| A029501 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02950101 | 22.03 | BIO001A02950102 | 22.52 | 11/2/2023 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | 2022 AFPR Recert Complete | |
| A029502 | Tier 1 | 3.0 | Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A02950201 | 16.71 | BIO001A02950202 | 16.80 | 11/2/2023 | None | Biodiesel | Imperial Western Products (9871) | Imperial Western Products (81066) | Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. | 2022 AFPR Recert Complete | |
| A029701 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0) | Kansas | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02970102 | 60.50 | LNG025A02970103 | 52.93 | 11/16/2023 | None | Bio-LNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A029702 | Tier 1 | 3.0 | Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0) | Kansas | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02970201 | 63.59 | LCN025A02970202 | 56.01 | 11/16/2023 | None | Bio-CNG | RENEWABLE POWER PRODUCERS, LLC (6504) | RENEWABLE POWER PRODUCERS, LLC (71289) | Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| A029801 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (3.0) | Washington | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02980101 | 28.80 | CNG025A02980102 | 29.30 | 11/28/2023 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A029802 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0) | Washington | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A02980201 | 42.58 | LNG025A02980202 | 38.46 | 11/28/2023 | None | Bio-LNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A029803 | Tier 1 | 3.0 | Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0) | Washington | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A02980301 | 45.67 | LCN025A02980302 | 41.55 | 11/28/2023 | None | Bio-CNG | PUGET SOUND ENERGY (6055) | CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109) | Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| A027601 | Tier 1 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (3.0) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02760100 | 47.41 | CNG025A02760101 | 45.83 | 11/6/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Meadow Branch Landfill Gas Processing Facility (71252) | Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel | 2022 AFPR Recert Complete | |
| A030601 | Tier 1 | 3.0 | Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (3.0) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03060101 | 42.85 | CNG025A03060102 | 43.27 | 11/17/2023 | None | Bio-CNG | MONROEVILLE LFG, LLC (6317) | MONROEVILLE LFG, LLC (71136) | Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A029101 | Tier 1 | 3.0 | Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (3.0) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A02910100 | 34.17 | CNG025A02910101 | 35.12 | 11/14/2023 | None | Bio-CNG | Morrow Renewables, LLC (C1224) | Pine Hill Renewables, LLC (71288) | Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A030201 | Tier 1 | 3.0 | Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (3.0) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03020100 | 34.00 | CNG025A03020101 | 34.04 | 11/14/2023 | None | Bio-CNG | Morrow Renewables, LLC (C1224) | Melissa Renewables, LLC (71407) | Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A030401 | Tier 1 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (3.0) | California | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A03040102 | 38.91 | CNG030A03040103 | 48.72 | 10/27/2023 | None | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | Point Loma Digester Gas Project (F00027) | Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. | 2022 AFPR Recert Complete | |
| B014301 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations (3.0) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B01430101 | -432.11 | CNG044B01430102 | -429.14 | 11/3/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Valley View Farm (70021S) | Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations | 2022 AFPR Recert Complete | |
| A030901 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A03090101 | 24.84 | ETH012A03090102 | 24.86 | 10/18/2023 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A030902 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A03090201 | 72.02 | ETH009A03090202 | 71.85 | 10/18/2023 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A030903 | Tier 1 | 3.0 | Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A03090300 | 68.76 | ETH009A03090301 | 68.28 | 10/18/2023 | None | Ethanol | Highwater Ethanol, LLC (3303) | Highwater Ethanol, LLC (70235) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A031001 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (3.0) | Louisiana | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03100100 | 41.18 | CNG025A03100101 | 41.37 | 11/28/2023 | None | Bio-CNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A031002 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (3.0) | Louisiana | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A03100201 | 55.55 | LNG025A03100202 | 50.02 | 11/28/2023 | None | Bio-LNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A031003 | Tier 1 | 3.0 | Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0) | Louisiana | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A03100301 | 58.64 | LCN025A03100302 | 53.11 | 11/28/2023 | None | Bio-CNG | River Birch, LLC (C1065) | River Birch Landfill (F00278) | Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| A031201 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0) | California | Soybean Oil (005) | Biodiesel (BIO) | BIO005A03120101 | 63.92 | BIO005A03120102 | 63.92 | 11/8/2023 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | 2022 AFPR Recert Complete | |
| A031202 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0) | California | Canola Oil (006) | Biodiesel (BIO) | BIO006A03120201 | 59.19 | BIO006A03120202 | 59.19 | 11/8/2023 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A031204 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. (3.0) | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A03120401 | 38.49 | BIO002A03120402 | 38.49 | 11/8/2023 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. | 2022 AFPR Recert Complete | |
| A031205 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0) | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A03120501 | 39.35 | BIO002A03120502 | 39.35 | 11/8/2023 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | 2022 AFPR Recert Complete | |
| A031206 | Tier 1 | 3.0 | Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A03120601 | 26.60 | BIO001A03120602 | 26.60 | 11/8/2023 | None | Biodiesel | Canary Renewables Corp. (C1201) | Canary Renewables Corp. Port of Stockton (82728) | US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production | 2022 AFPR Recert Complete | |
| B016601 | Tier 2 | 3.0 | Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (3.0) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B01660100 | -750.81 | ELC026B01660101 | -752.17 | 10/11/2023 | None | Electricity | SMUD (S338) | New Hope Dairy Digester (F00255) | Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. | 2022 AFPR Recert Complete | |
| A033001 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03300101 | 73.79 | ETH009A03300102 | 73.76 | 11/13/2023 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A033002 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03300200 | 63.46 | ETH009A03300201 | 62.43 | 11/13/2023 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A033003 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A03300300 | 25.32 | ETH012A03300301 | 24.72 | 11/13/2023 | None | Ethanol - Cellulosic | KAAPA Ethanol Holdings LLC (4805) | KAPPA Ethanol Ravenna LLC | Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A033201 | Tier 1 | 3.0 | Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A03320100 | 50.99 | ETH018A03320101 | 52.31 | 10/24/2023 | None | Ethanol | Usina São Martinho S.A. (3867) | Usina São Martinho S.A. (71100) | Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. | 2022 AFPR Recert Complete | |
| A033301 | Tier 1 | 3.0 | Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A03330100 | 50.06 | ETH018A03330101 | 50.36 | 10/25/2023 | None | Ethanol | Usina São Martinho S.A. (3867) | Santa Cruz S/A Açúcar e Álcool (70484) | Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. | 2022 AFPR Recert Complete | |
| A025201 | Tier 1 | 3.0 | Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A02520100 | 56.50 | ETH018A02520101 | 58.50 | 11/13/2023 | None | Ethanol | Companhia Alcoolquimica Nacional (C1086) | Companhia Alcoolquimica Nacional (F00194) | Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. | 2022 AFPR Recert Complete | |
| B017201 | Tier 2 | 3.0 | Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (3.0) | California | Corn (009) | Ethanol (ETH) | ETH009B01720100 | 65.68 | ETH009B01720101 | 64.07 | 11/27/2023 | None | Ethanol | Aemetis Advanced Fuels Keyes, Inc. (3566) | Aemetis Advanced Fuels Keyes, Inc. (70234) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI | 2022 AFPR Recert Complete | |
| B017301 | Tier 2 | 3.0 | Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (3.0) | Idaho | Dairy Manure (026) | Electricity (ELC) | ELC026B01730101 | -548.10 | ELC026B01730102 | -506.69 | 10/11/2023 | None | Electricity | DF-AP #1, LLC (C1122) | Big Sky Dairy Digester (F00329) | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A034501 | Tier 1 | 3.0 | Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. (3.0) | Michigan | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03450101 | 53.05 | CNG025A03450102 | 60.00 | 11/28/2023 | None | Bio-CNG | WESTSIDE GAS PRODUCERS, LLC (6218) | WESTSIDE GAS PRODUCERS, LLC (71151) | Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. | 2022 AFPR Recert Complete | |
| A034801 | Tier 1 | 3.0 | Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (3.0) | Texas | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A03480101 | 31.95 | BIO002A03480102 | 31.97 | 11/8/2023 | None | Biodiesel | Delek Renewables, LLC (5998) | Delek Renewables Cleburne Biodiesel Plant (81398) | U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail | 2022 AFPR Recert Complete | |
| A035101 | Tier 1 | 3.0 | Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03510101 | 67.49 | ETH009A03510102 | 68.01 | 11/27/2023 | None | Ethanol | E Energy Adams, LLC (4831) | E energy Adams, LLC (70093) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. | 2022 AFPR Recert Complete | |
| A035301 | Tier 1 | 3.0 | Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (3.0) | Colorado | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A03530100 | 52.36 | CNG030A03530101 | 46.66 | 11/14/2023 | None | Bio-CNG | South Platte Renew (8380) | 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641) | Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. | 2022 AFPR Recert Complete | |
| A036101 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A03610100 | 70.52 | ETH009A03610101 | 69.86 | 11/27/2023 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A036102 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0) | Indiana | Corn (009) | Ethanol (ETH) | ETH009A03610200 | 63.38 | ETH009A03610201 | 62.96 | 11/27/2023 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A036103 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0) | Indiana | Corn Fiber (012) | Ethanol (ETH) | ETH012A03610300 | 23.59 | ETH012A03610301 | 23.24 | 11/27/2023 | None | Ethanol | POET BIOREFINING - SHELBYVILLE (8841) | Poet Biorefining - Shelbyville (20621) | Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A036701 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (3.0) | Tennessee | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03670100 | 49.53 | CNG025A03670101 | 51.45 | 11/20/2023 | None | Bio-CNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| A036702 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (3.0) | Tennessee | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A03670201 | 63.18 | LNG025A03670202 | 58.99 | 11/20/2023 | None | Bio-LNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations | 2022 AFPR Recert Complete | |
| A036703 | Tier 1 | 3.0 | Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (3.0) | Tennessee | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A03670301 | 66.26 | LCN025A03670302 | 62.07 | 11/20/2023 | None | Bio-CNG | SOUTH SHELBY RNG, LLC (1236) | South Shelby RNG, LLC (71241) | Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG | 2022 AFPR Recert Complete | |
| B018501 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01850101 | -294.20 | CNG026B01850102 | -271.24 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B018502 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01850201 | -366.51 | CNG026B01850202 | -282.99 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use | 2022 AFPR Recert Complete | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018503 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01850300 | -382.11 | CNG026B01850301 | -401.96 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| A037501 | Tier 1 | 3.0 | Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (3.0) | Texas | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A03750101 | 38.37 | CNG025A03750102 | 41.43 | 11/6/2023 | None | Bio-CNG | BLUE SOURCE LLC (6086) | Seabreeze Energy Producers (70281) | Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG | 2022 AFPR Recert Complete | |
| B018701 | Tier 2 | 3.0 | Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (3.0) | Idaho | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01870101 | -421.53 | CNG026B01870102 | -421.46 | 10/30/2023 | None | Bio-CNG | Dry Creek RNG LLC (C1098) | Dry Creek RNG Project (F00342) | Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| A037801 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California (3.0) | Texas | Corn Fiber (012) | Ethanol (ETH) | ETH012A03780100 | 25.36 | ETH012A03780101 | 24.89 | 11/27/2023 | None | Ethanol - Cellulosic | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037802 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0) | Texas | Corn (009) | Ethanol (ETH) | ETH009A03780200 | 66.38 | ETH009A03780201 | 65.58 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037803 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03780301 | 66.40 | ETH010A03780302 | 66.40 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037804 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0) | Texas | Corn (009) | Ethanol (ETH) | ETH009A03780400 | 73.91 | ETH009A03780401 | 73.91 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (White Energy) (70039) | Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037805 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03780502 | 74.69 | ETH010A03780503 | 74.69 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | Plainview BioEnergy, LLC (70039) | Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037901 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (3.0) | Texas | Corn Fiber (012) | Ethanol (ETH) | ETH012A03790100 | 23.13 | ETH012A03790101 | 23.13 | 11/27/2023 | None | Ethanol - Cellulosic | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A037902 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0) | Texas | Corn (009) | Ethanol (ETH) | ETH009A03790200 | 63.93 | ETH009A03790201 | 63.93 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A037903 | Tier 1 | 3.0 | Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0) | Texas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A03790301 | 65.92 | ETH010A03790302 | 65.92 | 11/27/2023 | None | Ethanol | White Energy, Inc. (4745) | WE Hereford, LLC (70037) | Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| B018901 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Distillers' Corn Oil (003) | Renewable Naphtha (RNT) | RNT003B01890100 | 33.00 | RNT003B01890102 | 33.00 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018902 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B01890200 | 37.50 | RNT002B01890202 | 37.50 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018903 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | RNT002B01890300 | 26.00 | RNT002B01890302 | 26.00 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018904 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | RNT001B01890400 | 20.50 | RNT001B01890402 | 20.50 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018905 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Used Cooking Oil/Waste Oil (UCO) (001) | Renewable Naphtha (RNT) | RNT001B01890500 | 26.50 | RNT001B01890502 | 26.50 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018906 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B01890600 | 38.50 | RNT002B01890602 | 38.50 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018907 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B01890700 | 43.50 | RNT002B01890702 | 43.50 | 12/4/2023 | None | Renewable Naphtha | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018910 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891000 | 33.00 | LPG029B01891002 | 33.00 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018911 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891100 | 26.00 | LPG029B01891102 | 26.00 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018912 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891200 | 20.50 | LPG029B01891202 | 20.50 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018913 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891300 | 26.50 | LPG029B01891302 | 26.50 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018914 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891400 | 37.50 | LPG029B01891402 | 37.50 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B018915 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891500 | 38.50 | LPG029B01891502 | 38.50 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B018916 | Tier 2 | 3.0 | Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0) | Louisiana | Other Organic Waste (029) | Propane (LPG) | LPG029B01891600 | 43.50 | LPG029B01891602 | 43.50 | 12/4/2023 | None | Propane | REG Geismar, LLC (6268) | REG Geismar, LLC (80180) | Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker | 2022 AFPR Recert Complete | |
| B019701 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01970100 | -177.03 | CNG026B01970101 | -208.60 | 10/30/2023 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | 2022 AFPR Recert Complete | |
| B019702 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01970200 | -156.78 | CNG026B01970201 | -149.41 | 10/30/2023 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | 2022 AFPR Recert Complete | |
| B019703 | Tier 2 | 3.0 | Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0) | Indiana | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01970300 | -295.26 | CNG026B01970301 | -332.22 | 10/30/2023 | None | Bio-CNG | Generate Indiana RNG Holdings, LLC (9889) | Generate Jasper Upgrader, LLC (71002) | Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California | 2022 AFPR Recert Complete | |
| A038501 | Tier 1 | 3.0 | Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (3.0) | California | Wastewater Sludge (030) | Compressed Natural Gas (CNG) | CNG030A03850100 | 19.28 | CNG030A03850101 | 19.28 | 10/30/2023 | None | Bio-CNG | Los Angeles County Sanitation District (L375) | Biogas Conditioning System Facility (F00308) | Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. | 2022 AFPR Recert Complete | |
| B019801 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980101 | -294.40 | CNG026B01980102 | -343.44 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B019802 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980200 | -414.26 | CNG026B01980201 | -419.15 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B019803 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980300 | -420.69 | CNG026B01980301 | -413.34 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B019804 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980400 | -405.41 | CNG026B01980401 | -324.70 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B019805 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B01980500 | -385.40 | CNG026B01980501 | -420.53 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| A025801 | Tier 1 | 3.0 | Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A02580100 | 51.59 | ETH018A02580101 | 53.00 | 10/18/2023 | None | Ethanol | Agro Industrial Tabu S.A. (C1088) | Agro Industrial Tabu (F00205) | Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. | 2022 AFPR Recert Complete | |
| A038601 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A03860101 | 72.76 | ETH009A03860102 | 72.28 | 11/27/2023 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |

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|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A038602 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0) | South Dakota | Corn (009) | Ethanol (ETH) | ETH009A03860201 | 69.61 | ETH009A03860202 | 69.01 | 11/27/2023 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A038603 | Tier 1 | 3.0 | Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0) | South Dakota | Corn Fiber (012) | Ethanol (ETH) | ETH012A03860300 | 28.03 | ETH012A03860301 | 26.18 | 11/27/2023 | None | Ethanol | Valero Renewable Fuels (3201) | Valero Renewable Fuels Aurora (70041) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A039401 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03940101 | 66.77 | ETH009A03940102 | 66.96 | 11/27/2023 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. | 2022 AFPR Recert Complete | |
| A039402 | Tier 1 | 3.0 | Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A03940201 | 27.95 | ETH012A03940202 | 27.99 | 11/27/2023 | None | Ethanol | America Agri Products/Wheatland, LLC (5095) | Mid America Agri Products/Wheatland LLC (70153) | Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. | 2022 AFPR Recert Complete | |
| A039601 | Tier 1 | 3.0 | Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A03960100 | 52.79 | ETH018A03960101 | 53.07 | 11/13/2023 | None | Ethanol | Adecoagro Brasil Participacoes (4192) | Adecoagro Vale do Ivinhema Ltda. (70496) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | 2022 AFPR Recert Complete | |
| A039701 | Tier 1 | 3.0 | Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. (3.0) | North Dakota | Canola Oil (006) | Biodiesel (BIO) | BIO006A03970100 | 47.44 | BIO006A03970101 | 46.43 | 10/31/2023 | None | Biodiesel | Archer Daniels Midland Co (4888) | ADM Velva (82790) | Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. | 2022 AFPR Recert Complete | |
| B020701 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02070101 | -132.51 | CNG026B02070102 | -136.71 | 10/30/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations | 2022 AFPR Recert Complete | |
| B020702 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02070201 | -193.95 | CNG026B02070202 | -185.59 | 10/30/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | Dane Renewable Energy, LLC (F00235) | Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations | 2022 AFPR Recert Complete | |
| A040401 | Tier 1 | 3.0 | Fuel Producer: Cargill Biodiesel (3683); Facility Name: Cargill Incorporated (36833); Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel. (3.0) | Iowa | Soybean Oil (005) | Biodiesel (BIO) | BIO005A04040100 | 54.36 | BIO005A04040101 | 54.75 | 11/16/2023 | None | Biodiesel | Cargill Biodiesel (3683) | Cargill Incorporated (36833) | Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel. | 2022 AFPR Recert Complete | |
| B021401 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (PROV3.0) | Utah | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02140100 | -413.67 | CNG044B02140101 | -417.05 | 12/11/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Milford Farm (71483) | Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional) | 2022 AFPR Recert Complete | |
| B021501 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02150100 | -310.71 | CNG026B02150101 | -337.05 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B021502 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | LNG026B02150200 | -296.99 | LNG026B02150201 | -320.23 | 11/22/2023 | None | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B021503 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | LCN026B02150300 | -293.45 | LCN026B02150301 | -316.68 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | Rosendale Renewable Energy, LLC (71041) | Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG | 2022 AFPR Recert Complete | |
| B021601 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02160101 | -333.34 | CNG026B02160102 | -225.64 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B021602 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | LNG026B02160201 | -318.76 | LNG026B02160202 | -207.44 | 11/22/2023 | None | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG | 2022 AFPR Recert Complete | |
| B021603 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | LCN026B02160301 | -315.22 | LCN026B02160302 | -203.89 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | KEWAUNEE RENEWABLE ENERGY, LLC (71003) | Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG | 2022 AFPR Recert Complete | |
| B021701 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02170101 | -274.25 | CNG026B02170102 | -234.87 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B021702 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Natural Gas (LNG) | LNG026B02170201 | -259.30 | LNG026B02170202 | -217.46 | 11/22/2023 | None | Bio-LNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use | 2022 AFPR Recert Complete | |
| B021703 | Tier 2 | 3.0 | Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (3.0) | Wisconsin | Dairy Manure (026) | Liquefied Compressed Natural Gas (LCN) | LCN026B02170301 | -255.76 | LCN026B02170302 | -213.91 | 11/22/2023 | None | Bio-CNG | DTE ENERGY TRADING, INC. (6545) | NEW CHESTER RENEWABLE ENERGY, LLC (71181) | Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG | 2022 AFPR Recert Complete | |
| B021901 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (3.0) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02190101 | -359.22 | CNG044B02190102 | -403.69 | 11/3/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | HOMAN FARM (71343) | RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| B022001 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (3.0) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B02200102 | -370.44 | CNG044B02200103 | -382.99 | 10/30/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | SOMERSET FARM (71381) | Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use | 2022 AFPR Recert Complete | |
| A041601 | Tier 1 | 3.0 | Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (PROV3.0) | Pennsylvania | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A04160101 | 71.21 | CNG025A04160102 | 74.90 | 10/31/2023 | None | Bio-CNG | TRUSTAR ENERGY LLC (6523) | Greentree Landfill Gas Company (F00212) | Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional) | 2022 AFPR Recert Complete | |
| A042301 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A04230101 | 72.01 | ETH009A04230102 | 72.25 | 11/28/2023 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| A042302 | Tier 1 | 3.0 | Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A04230201 | 24.42 | ETH012A04230202 | 24.71 | 11/28/2023 | None | Ethanol | Homeland Energy Solutions LLC (3220) | Homeland Energy Solutions LLC (70188) | Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A042501 | Tier 1 | 3.0 | Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. (3.0) | Canada | Canola Oil (006) | Biodiesel (BIO) | BIO006A04250100 | 47.65 | BIO006A04250101 | 46.82 | 10/31/2023 | None | Biodiesel | ADM Agri-Industries Company (6137) | ADM Agri Industries (81926) | Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. | 2022 AFPR Recert Complete | |
| A043601 | Tier 1 | 3.0 | Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0) | Minnesota | Corn (009) | Ethanol (ETH) | ETH009A04360100 | 71.53 | ETH009A04360101 | 72.42 | 11/28/2023 | None | Ethanol | AL CORN CLEAN FUEL, LLC (4825) | AL CORN CLEAN FUEL, LLC (70087) | Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| A043602 | Tier 1 | 3.0 | Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0) | Minnesota | Corn Fiber (012) | Ethanol (ETH) | ETH012A04360201 | 25.15 | ETH012A04360202 | 25.90 | 11/28/2023 | None | Ethanol | AL CORN CLEAN FUEL, LLC (4825) | AL CORN CLEAN FUEL, LLC (70087) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| A043701 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (PROV3.0) | Oklahoma | Landfill Gas (025) | Compressed Natural Gas (CNG) | CNG025A04370100 | 37.00 | CNG025A04370101 | 37.00 | 11/20/2023 | None | Bio-CNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional) | 2022 AFPR Recert Complete | |
| A043702 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (PROV3.0) | Oklahoma | Landfill Gas (025) | Liquefied Natural Gas (LNG) | LNG025A04370200 | 50.61 | LNG025A04370201 | 53.28 | 11/20/2023 | None | Bio-LNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional) | 2022 AFPR Recert Complete | |
| A043703 | Tier 1 | 3.0 | Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (PROV3.0) | Oklahoma | Landfill Gas (025) | Liquefied Compressed Natural Gas (LCN) | LCN025A04370300 | 53.70 | LCN025A04370301 | 56.37 | 11/20/2023 | None | Bio-CNG | LYNX RENEWABLE ENERGY LLC (1392) | Lynx Renewable Energy (F00355) | Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional) | 2022 AFPR Recert Complete | |
| B025001 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02500100 | -182.67 | CNG026B02500101 | -187.55 | 10/25/2023 | None | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B025002 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02500200 | -267.51 | CNG026B02500201 | -258.09 | 10/25/2023 | None | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B025003 | Tier 2 | 3.0 | Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0) | Minnesota | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02500300 | -255.34 | CNG026B02500301 | -224.53 | 10/25/2023 | None | Bio-CNG | AMPRENEW OFFTAKE I LLC (9041) | RDF STEVENS LLC (71701) | Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| A044001 | Tier 1 | 3.0 | Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A04400100 | 72.37 | ETH009A04400101 | 74.48 | 11/27/2023 | None | Ethanol | Element, LLC (C1020) | Element (F00048) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A044002 | Tier 1 | 3.0 | Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A04400200 | 62.07 | ETH009A04400201 | 64.11 | 11/27/2023 | None | Ethanol | Element, LLC (C1020) | Element (F00048) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California | 2022 AFPR Recert Complete | |
| A044201 | Tier 1 | 3.0 | Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A04420100 | 72.16 | ETH009A04420101 | 72.23 | 10/17/2023 | None | Ethanol | Lincolnway Energy, LLC (4830) | Lincolnway Energy (70092) | Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A044203 | Tier 1 | 3.0 | Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A04420300 | 24.70 | ETH012A04420301 | 24.99 | 10/17/2023 | None | Ethanol - Cellulosic | Lincolnway Energy, LLC (4830) | Lincolnway Energy (70092) | Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| B026701 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0) | California | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003B02670101 | 28.80 | BIO003B02670102 | 28.73 | 10/31/2023 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2022 AFPR Recert Complete | |
| B026702 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002B02670201 | 32.73 | BIO002B02670202 | 32.74 | 10/31/2023 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2022 AFPR Recert Complete | |
| B026703 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001B02670300 | 15.71 | BIO001B02670301 | 15.58 | 10/31/2023 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2022 AFPR Recert Complete | |
| B026704 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001B02670400 | 16.34 | BIO001B02670401 | 16.15 | 10/31/2023 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2022 AFPR Recert Complete | |
| B026705 | Tier 2 | 3.0 | Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001B02670500 | 20.86 | BIO001B02670501 | 20.74 | 10/31/2023 | None | Biodiesel | Crimson Renewable Energy LLC (4814) | Crimson Renewable Energy Bakersfield Biodiesel Plant (80174) | North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional) | 2022 AFPR Recert Complete | |
| A045001 | Tier 1 | 3.0 | Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0) | Pennsylvania | Soybean Oil (005) | Biodiesel (BIO) | BIO005A04500100 | 58.09 | BIO005A04500101 | 57.93 | 11/2/2023 | None | Biodiesel | WORLD ENERGY HARRISBURG LLC (6425) | WORLD ENERGY HARRISBURG LLC (81499) | Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. | 2022 AFPR Recert Complete | |
| A045002 | Tier 1 | 3.0 | Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0) | Pennsylvania | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001A04500200 | 21.59 | BIO001A04500201 | 20.78 | 11/2/2023 | None | Biodiesel | WORLD ENERGY HARRISBURG LLC (6425) | WORLD ENERGY HARRISBURG LLC (81499) | US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. | 2022 AFPR Recert Complete | |
| B026801 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02680101 | 18.93 | AJF002B02680103 | 22.00 | 12/14/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026802 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02680201 | 18.93 | RND002B02680203 | 22.00 | 12/14/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026803 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02680301 | 18.93 | RNT002B02680303 | 22.00 | 12/14/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026804 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02680400 | 19.54 | AJF002B02680402 | 22.00 | 12/14/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B026805 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02680500 | 19.54 | RND002B02680502 | 22.00 | 12/14/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026806 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02680600 | 19.54 | RNT002B02680602 | 22.00 | 12/14/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026807 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02680700 | 15.64 | AJF002B02680701 | 17.98 | 12/12/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026808 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02680800 | 15.64 | RND002B02680801 | 17.98 | 12/12/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026809 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02680900 | 15.64 | RNT002B02680901 | 17.98 | 12/12/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026810 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02681001 | 29.78 | AJF002B02681003 | 32.00 | 12/14/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026811 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02681101 | 29.78 | RND002B02681103 | 32.00 | 12/14/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026812 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02681201 | 29.78 | RNT002B02681203 | 32.00 | 12/14/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026813 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02681300 | 32.93 | AJF002B02681301 | 37.00 | 12/12/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026814 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02681400 | 32.93 | RND002B02681401 | 37.00 | 12/12/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026815 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02681500 | 32.93 | RNT002B02681501 | 37.00 | 12/12/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026816 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Alternative Jet Fuel (AJF) | AJF002B02681600 | 38.43 | AJF002B02681601 | 43.00 | 12/12/2023 | None | Alternative Jet Fuel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B026817 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Diesel (RND) | RND002B02681700 | 38.43 | RND002B02681701 | 43.00 | 12/12/2023 | None | Renewable Diesel | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B026818 | Tier 2 | 3.0 | Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0) | California | Tallow (animal and poultry fat) (002) | Renewable Naphtha (RNT) | RNT002B02681800 | 38.43 | RNT002B02681801 | 43.00 | 12/12/2023 | None | Renewable Naphtha | AltAir Paramount, LLC (6281) | AltAir Paramount, LLC (83180) | Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional) | 2022 AFPR Recert Complete | |
| B028201 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02820100 | -272.08 | CNG026B02820101 | -360.00 | 10/30/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | U.S. GAIN RNG FACILITY S&S (71361) | Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use | 2022 AFPR Recert Complete | |
| B028301 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B02830100 | -195.09 | CNG026B02830101 | -194.44 | 10/27/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | DEER RUN RNG PROJECT (71482) | Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| A045601 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0) | California | Distillers' Corn Oil (003) | Biodiesel | BIO003A04560100 | 30.15 | BIO003A04560101 | 34.64 | 11/3/2023 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL (80341) | California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals | 2022 AFPR Recert Complete | |
| A045602 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0) | California | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel | BIO001A04560200 | 23.48 | BIO001A04560201 | 27.73 | 11/3/2023 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL (80341) | North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals | 2022 AFPR Recert Complete | |
| A045603 | Tier 1 | 3.0 | Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL ( 80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0) | California | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002A04560300 | 36.09 | BIO002A04560301 | 40.98 | 11/3/2023 | None | Biodiesel | SJV BIODIESEL LLC (7501) | SJV BIODIESEL ( 80341) | North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals | 2022 AFPR Recert Complete | |
| A041001 | Tier 1 | 3.0 | Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | ETH018A04100100 | 52.77 | ETH018A04100101 | 53.00 | 10/25/2023 | None | Ethanol | JAPUNGU AGROINDUSTRIAL LTDA (C1145) | Japungu Agroindustrial Ltda (F00383) | Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. | 2022 AFPR Recert Complete | |
| B030201 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0) | Minnesota | Distillers' Corn Oil (003) | Biodiesel (BIO) | BIO003B03020100 | 24.50 | BIO003B03020102 | 24.50 | 12/4/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California | 2022 AFPR Recert Complete | |
| B030202 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001B03020200 | 18.50 | BIO001B03020202 | 18.50 | 12/4/2023 | None | Renewable Diesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California | 2022 AFPR Recert Complete | |
| B030203 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0) | Minnesota | Used Cooking Oil/Waste Oil (UCO) (001) | Biodiesel (BIO) | BIO001B03020300 | 12.50 | BIO001B03020302 | 12.50 | 12/4/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California | 2022 AFPR Recert Complete | |
| B030204 | Tier 2 | 3.0 | Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (3.0) | Minnesota | Tallow (animal and poultry fat) (002) | Biodiesel (BIO) | BIO002B03020400 | 29.00 | BIO002B03020402 | 29.00 | 12/4/2023 | None | Biodiesel | REG Albert Lea, LLC (4305) | REG Albert Lea, LLC (82613) | North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B030701 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03070100 | -353.38 | CNG026B03070101 | -325.32 | 10/27/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B030702 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03070200 | -405.57 | CNG026B03070201 | -361.69 | 10/27/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B030703 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03070300 | -255.83 | CNG026B03070301 | -256.77 | 10/27/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B030704 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03070400 | -249.43 | CNG026B03070401 | -247.40 | 10/27/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B030705 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03070500 | -366.91 | CNG026B03070501 | -411.56 | 10/27/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Hanford LLC (F00435) | Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031001 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100100 | -349.17 | CNG026B03100101 | -420.78 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031002 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100200 | -210.67 | CNG026B03100201 | -257.14 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031003 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100300 | -406.28 | CNG026B03100301 | -415.27 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031004 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100400 | -417.26 | CNG026B03100401 | -372.09 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031005 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100500 | -417.24 | CNG026B03100501 | -369.61 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031006 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03100600 | -356.29 | CNG026B03100601 | -324.13 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas North Visalia LLC (F00433) | Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031101 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110101 | -418.04 | CNG026B03110102 | -348.56 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| B031102 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110200 | -383.14 | CNG026B03110201 | -336.76 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031103 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110300 | -419.34 | CNG026B03110301 | -423.14 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031104 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110400 | -299.39 | CNG026B03110401 | -334.72 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031105 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110500 | -276.38 | CNG026B03110501 | -307.02 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031106 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110600 | -403.86 | CNG026B03110601 | -392.14 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031107 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110700 | -341.84 | CNG026B03110701 | -318.92 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B031108 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03110800 | -273.88 | CNG026B03110801 | -331.28 | 11/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas South Tulare LLC (F00434) | Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| A046201 | Tier 1 | 3.0 | Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (PROV3.0) | | Corn Fiber (012) | Ethanol (ETH) | ETH012A04620101 | 33.08 | ETH012A04620103 | 34.36 | 10/17/2023 | None | Ethanol | CORN, LP (5065) | CORN, LP (70145) | Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional) | 2022 AFPR Recert Complete | |
| A046202 | Tier 1 | 3.0 | Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (PROV3.0) | | Corn (009) | Ethanol (ETH) | ETH009A04620201 | 70.62 | ETH009A04620202 | 73.77 | 10/17/2023 | None | Ethanol | CORN, LP (5065) | CORN, LP (70145) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional) | 2022 AFPR Recert Complete | |
| B031501 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03150100 | -403.96 | CNG026B03150101 | -409.96 | 12/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas West Visalia LLC (F00337) | Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B033801 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (PROV3.0) | Texas | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B03380100 | -417.96 | CNG044B03380101 | -430.20 | 12/11/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | DALHART RNG, LLC (70981) | Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B034501 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03450100 | -318.35 | CNG026B03450101 | -296.42 | 10/27/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET LAKESHORE RNG PROJECT (71321) | Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
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| B034601 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (PROV3.0) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03460100 | -311.72 | CNG026B03460101 | -272.73 | 11/22/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET LAMB RNG PROJECT (71101) | Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B035301 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03530100 | -344.72 | CNG026B03530101 | -319.04 | 10/30/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | U.S. GAIN RNG FACILITY DALLMAN (71341) | Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use | 2022 AFPR Recert Complete | |
| B035201 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03520100 | -411.77 | CNG026B03520101 | -423.12 | 12/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B035202 | Tier 2 | 3.0 | Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (PROV3.0) | California | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03520200 | -351.51 | CNG026B03520201 | -353.82 | 12/14/2023 | None | Bio-CNG | California Bioenergy LLC (B194) | CalBioGas Kern LLC (F00336) | Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B036601 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (3.0) | Utah | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B03660100 | -414.59 | CNG044B03660101 | -427.14 | 10/30/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | MILFORD FARM (71483) | Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use | 2022 AFPR Recert Complete | |
| B036001 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | HYG026B03600100 | -159.04 | HYG026B03600101 | -154.83 | 11/6/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |
| B036002 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | HYL026B03600200 | -120.27 | HYL026B03600201 | -118.90 | 11/6/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |
| B036003 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | HYL026B03600300 | -104.64 | HYL026B03600301 | -100.09 | 11/6/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |
| B037001 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (PROV3.0) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B03700100 | -408.25 | CNG044B03700101 | -402.51 | 10/27/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | GREEN HILLS FARM (71881) | Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B037101 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (PROV3.0) | Missouri | Swine Manure (044) | Compressed Natural Gas (CNG) | CNG044B03710100 | -412.77 | CNG044B03710101 | -374.61 | 10/27/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | WHITETAIL FARM (71882) | Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B037302 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | HYL026B03730200 | -192.70 | HYL026B03730201 | -182.54 | 11/13/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |
| B037304 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Gaseous Hydrogen (HYG) | HYG026B03730400 | -231.46 | HYG026B03730401 | -218.47 | 11/13/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
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| B037306 | Tier 2 | 3.0 | Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (PROV3.0) | California | Dairy Manure (026) | Liquid Hydrogen (HYL) | HYL026B03730600 | -177.06 | HYL026B03730601 | -163.73 | 11/13/2023 | None | Hydrogen | FirstElement Fuel (E426) | Praxair SMR facility (F00394) | L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional) | 2022 AFPR Recert Complete | |
| A049001 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A04900100 | 71.51 | ETH009A04900101 | 71.65 | 10/25/2023 | None | Ethanol | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| A049002 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | ETH009A04900200 | 61.15 | ETH009A04900201 | 61.71 | 10/25/2023 | None | Ethanol | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional) | 2022 AFPR Recert Complete | |
| A049003 | Tier 1 | 3.0 | Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | ETH012A04900300 | 22.33 | ETH012A04900301 | 23.74 | 10/25/2023 | None | Ethanol - Cellulosic | Southwest Iowa Renewable Energy, LLC (5935) | Southwest Iowa Renewable Energy, LLC (70326) | Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional) | 2022 AFPR Recert Complete | |
| B038201 | Tier 2 | 3.0 | Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (3.0) | California | Dairy Manure (026) | Electricity (ELC) | ELC026B03820100 | -758.40 | ELC026B03820101 | -756.17 | 11/27/2023 | None | Electricity | Madera Renewable Energy, LLC (C1140) | Madera Renewable Energy, LLC (F00436) | Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. | 2022 AFPR Recert Complete | |
| B038501 | Tier 2 | 3.0 | Fuel Producer: Anew RNG, LLC (5877); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0) | Wisconsin | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B03850100 | -180.73 | CNG026B03850101 | -180.62 | 11/28/2023 | None | Bio-CNG | Anew RNG, LLC (5877) | Green Valley Dairy LLC (F00198) | Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B040101 | Tier 2 | 3.0 | Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (PROV3.0) | New York | Dairy Manure (026) | Compressed Natural Gas (CNG) | CNG026B04010100 | -216.27 | CNG026B04010101 | -187.99 | 11/22/2023 | None | Bio-CNG | U.S. Venture, Inc. (5504) | YELLOW JACKET SWISS VALLEY RNG PROJECT (71161) | Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional) | 2022 AFPR Recert Complete | |
| B042801 | Tier 2 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0) | Mississippi | Distillers' Corn Oil (003) | Renewable Diesel (RND) | RND003B04280100 | 51.80 | RND003B04280101 | 53.52 | 11/6/2023 | None | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | 2022 AFPR Recert Complete | |
| B042802 | Tier 2 | 3.0 | Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0) | Mississippi | Soybean Oil (005) | Renewable Diesel (RND) | RND005B04280200 | 80.81 | RND005B04280201 | 83.76 | 11/6/2023 | None | Renewable Diesel | Jaxon Energy, LLC (6454) | Jaxon Energy, LLC (83608) | Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional) | 2022 AFPR Recert Complete | |
| B048501 | Tier 2 | 3.0 | Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: SANCO Services Anaerobic Digestor Plant (F00478); Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (PROV3.0) | California | Other Organic Waste (029) | Compressed Natural Gas (CNG) | None | None | CNG029B04850100 | -38.80 | 1/2/2024 | Application Package | Bio-CNG | Trillium Transportation Fuels, LLC (T311) | SANCO Services Anaerobic Digestor Plant (F00478) | Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (Provisional) | None | |
| B052101 | Tier 2 | 3.0 | Fuel Producer: PHILLIPS 66 COMPANY (4528) ; Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline. (3.0) | California | Soybean Oil (005) | Renewable Gasoline (RNG) | None | None | RNG005B05210100 | 67.35 | 12/29/2023 | Application Package | Renewable Gasoline | PHILLIPS 66 COMPANY (4528) | Phillips 66 Rodeo (82191) | Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline. | None | |
| A019801 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A01980103 | 62.37 | ETH009A01980105 | 62.23 | 1/9/2024 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI | 2022 AFPR Recert Complete | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A019802 | Tier 1 | 3.0 | Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | ETH012A01980201 | 23.04 | ETH012A01980202 | 22.96 | 11/13/2023 | None | Ethanol | KAAPA Ethanol Holdings LLC (4805) | KAAPA Ethanol LLC (70079) | Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California | 2022 AFPR Recert Complete | |
| A053001 | Tier 1 | 3.0 | Fuel Producer: Guarani SA (3833); Facility Name: Usina Vertente Ltda. (70447); Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker. (3.0) | Brazil | Sugarcane (018) | Ethanol (ETH) | None | None | ETH018A05300100 | 48.78 | 1/8/2024 | None | Ethanol | Guarani SA (3833) | Usina Vertente Ltda. (70447) | Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker. | None | |
| A053201 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (PROV3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05320100 | 66.20 | 1/11/2024 | None | Ethanol | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (Provisional) | None | |
| A053202 | Tier 1 | 3.0 | Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (PROV3.0) | Iowa | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05320200 | 26.80 | 1/11/2024 | None | Ethanol - Cellulosic | Elite Octane, LLC (6500) | Elite Octane, LLC (71287) | Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (Provisional) | None | |
| A054001 | Tier 1 | 3.0 | Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0) | South Dakota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05400100 | 72.33 | 1/23/2024 | None | Ethanol | NuGen Energy, LLC (3332) | NuGen Energy, LLC (70195) | Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity, Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional) | None | |
| A054002 | Tier 1 | 3.0 | Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0) | South Dakota | Grain Sorghum (010) | Ethanol (ETH) | None | None | ETH010A05400200 | 76.07 | 1/23/2024 | None | Ethanol | NuGen Energy, LLC (3332) | NuGen Energy, LLC (70195) | Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional) | None | |
| A053601 | Tier 1 | 3.0 | Fuel Producer: Green Plains Superior LLC (5851); Facility Name: GREEN PLAINS SUPERIOR, LLC (70304); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI. (3.0) | Iowa | Corn (009) | Ethanol (ETH) | None | None | ETH009A05360100 | 70.98 | 1/31/2024 | None | Ethanol | Green Plains Superior LLC (5851) | GREEN PLAINS SUPERIOR, LLC (70304) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI. | None | |
| A054101 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (PROV3.0) | Kansas | Corn (009) | Ethanol (ETH) | ETH009A01030102 | 71.24 | ETH009A05410100 | 63.36 | 1/26/2024 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (Provisional) | None | |
| A054102 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (PROV3.0) | Kansas | Grain Sorghum (010) | Ethanol (ETH) | ETH010A01030602 | 73.44 | ETH010A05410200 | 67.05 | 1/26/2024 | None | Ethanol | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (Provisional) | None | |
| A054103 | Tier 1 | 3.0 | Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (PROV3.0) | Kansas | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05410300 | 25.05 | 1/26/2024 | None | Ethanol - Cellulosic | Bonanza BioEnergy, LLC (4054) | Bonanza BioEnergy, LLC (70117) | Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (Provisional) | None | |
| A053701 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03070100 | 74.08 | ETH009A05370100 | 78.02 | 2/9/2024 | None | Ethanol | POET BIOREFINING - FAIRMONT (1579) | FAIRMONT (71681) | Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional) | None | |
| A053702 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | ETH009A03070200 | 69.42 | ETH009A05370200 | 75.27 | 2/9/2024 | None | Ethanol | POET BIOREFINING - FAIRMONT (1579) | FAIRMONT (71681) | Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional) | None | |

| App/Pathway # | Class | Calculator Version | Applicant & Pathway Description | Facility Location | Feedstock | Fuel Type | Legacy FPC | Legacy CI | Current Certified FPC | Current Certified CI | Certification Date | Postings and Comments | Fuel Category | Company (ID) | Facility (ID) | Pathway Description | AFPR Recertification Status | Retired Pathway |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A053703 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0) | Nebraska | Corn (009) | Ethanol (ETH) | None | None | ETH009A05370300 | 69.59 | 2/9/2024 | None | Ethanol | POET BIOREFINING - FAIRMONT (1579) | FAIRMONT (71681) | Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional) | None | |
| A053704 | Tier 1 | 3.0 | Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0) | Nebraska | Corn Fiber (012) | Ethanol (ETH) | None | None | ETH012A05370400 | 30.06 | 2/9/2024 | None | Ethanol - Cellulosic | POET BIOREFINING - FAIRMONT (1579) | FAIRMONT (71681) | Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional) | None | |
| A053901 | Tier 1 | 3.0 | Fuel Producer: Green Plains Otter Tail LLC (4180); Facility Name: GREEN PLAINS OTTER TAIL, LLC (70110); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI. (3.0) | Minnesota | Corn (009) | Ethanol (ETH) | None | None | ETH009A05390100 | 72.83 | 2/1/2024 | None | Ethanol | Green Plains Otter Tail LLC (4180) | GREEN PLAINS OTTER TAIL, LLC (70110) | Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI. | None | |

# ATTACHMENT L

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT**: C-9169-1-0 **EXPIRATION DATE**: 10/31/2026

**EQUIPMENT DESCRIPTION**:
DIGESTER GAS OPERATION CONSISTING OF A 36,000,000 GALLON (EQUIVALENT TO 412'X507'X21.5') ANAEROBIC DIGESTER LAGOON WITH AN AIR/OXYGEN INJECTION SYSTEM FOR H2S CONTROL AND A GAS COLLECTION AND HANDLING SYSTEM SERVED BY A H2S SCRUBBER

## PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The digester system shall be designed to allow gas generated to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
4. The air/oxygen injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
5. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
6. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rule 1070]

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT**: C-9169-4-0 **EXPIRATION DATE**: 10/31/2026

**EQUIPMENT DESCRIPTION**:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

## PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT**: C-9169-5-0 **EXPIRATION DATE**: 10/31/2026

**EQUIPMENT DESCRIPTION**:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

## PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT**: C-9169-6-0 **EXPIRATION DATE**: 10/31/2026

**EQUIPMENT DESCRIPTION**:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

## PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

# San Joaquin Valley
# Air Pollution Control District

**PERMIT UNIT**: C-9169-7-0 **EXPIRATION DATE**: 10/31/2026

**EQUIPMENT DESCRIPTION**:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

## PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

# ATTACHMENT M

**San Joaquin Valley**
**AIR POLLUTION CONTROL DISTRICT**

**HEALTHY AIR LIVING™**

FEB 21 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

**Re: Notice of Preliminary Decision - Authority to Construct**
**Facility Number: C-9133**
**Project Number: C-1193519**

Dear Mr. Bryant:

Enclosed for your review and comment is the District's analysis of Lone Oak Energy LLC's application for an Authority to Construct for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jesse A. Garcia of Permit Services at (559) 230-5918.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

# San Joaquin Valley Air Pollution Control District

## Authority to Construct Application Review

### Installation of a Digester Gas-Fired IC Engine with SCR

| | |
|---|---|
| Facility Name: | Lone Oak Energy LLC |
| Mailing Address: | 2911 Hanford Armona Rd<br>Hanford, CA 93230 |
| Contact Person: | Doug Bryant |
| Telephone: | (207) 691-8068 |
| E-Mail: | doug@maasenergy.com |
| Application #(s): | C-9133-3-0 |
| Project #: | C-1193519 |
| Deemed Complete: | December 9, 2019 |

| | |
|---|---|
| Date: | January 22, 2020 |
| Engineer: | Jesse A. Garcia |
| Lead Engineer: | Jerry Sandhu |

---

## I. Proposal

Lone Oak Energy LLC has requested an Authority to Construct (ATC) to install a 1,306 bhp digester gas-fired IC engine powering an electrical generator. This IC engine was originally permitted under ATC C-9133-1-0; however, the applicant has requested higher $NO_X$, CO and VOC emission factors during normal operation after the commissioning period. A summary of the emission factors from ATC -1-0 and the ones proposed under this project are shown in the following table:

| Summary of Emission Factor Changes (ppmv) | | |
|---|---|---|
| **Pollutant** | **From ATC -1-0** | **Proposed in this Project** |
| $NO_X$ | 5 | 10 |
| CO | 15 | 223 |
| VOC | 10 | 20 |

Since the equipment being permitted in this project was also authorized under ATC -1-0, the ATC issued in this project will cancel and supersede ATC -1-0 and the following condition will be included on the ATC:

- This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]

## II. Applicable Rules

Rule 1070 Inspections (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410 Prevention of Significant Deterioration (6/16/11)

Rule 2520 Federally Mandated Operating Permits (8/15/19)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emission Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4701 Internal Combustion Engines - Phase 1 (8/21/03)
Rule 4702 Internal Combustion Engines (11/14/13)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

## III. Project Location

The facility is located at 10014 S McMullin Grade in Hanford, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

## IV. Process Description

The applicant is proposing to install one 1,306 bhp Caterpillar lean burn digester gas-fired IC engine. The engine will be equipped with an SCR system and an oxidation catalyst for emissions control and will power a generator. The electricity generated by this operation will be sold to utility grid. The engine will be permitted to operate up to 24 hours per day and 120 hours per year during the commissioning period (the time allowed during initial startup of the engine to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system and/or oxidation catalyst) and up to 24 hours per day and 8,500 hours per year after the commissioning period.

## V. Equipment Listing

C-9133-3-0: 1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

## VI. Emission Control Technology Evaluation

The proposed engine will be equipped with:

- Turbocharger
- Intercooler
- Positive Crankcase Ventilation (PCV)
- Air/Fuel Ratio or an $O_2$ Controller
- Lean Burn Technology

- Oxidation Catalyst
- Selective Catalytic Reduction (SCR)

The turbocharger reduces the NOx emission rate from the engine by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NOx.

The PCV system reduces crankcase VOC and $PM_{10}$ emissions by at least 90% over an uncontrolled crankcase vent.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NOx formation.

An oxidation catalyst converts CO and VOC emissions to $CO_2$ and water. Typically, these catalysts are located prior to the urea injection site since the oxidation catalyst would otherwise convert the excess ammonia into NOx.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, are passed through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it reacts and reduces NOx, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

Additionally, prior to being combusted in the engine, the digester gas will be treated in a gas conditioning system to reduce the $H_2S$ such that the sulfur content will not exceed 40 ppmv as $H_2S$.

## VII. General Calculations

### A. Assumptions

- To streamline emission calculations, $PM_{2.5}$ emissions are assumed to be equal to $PM_{10}$ emissions.
- Higher Heating Value (HHV) for Digester Gas: 700 Btu/scf (proposed by the applicant, based on 70% methane content, also used in other similar District projects)
- Typical EPA F-factor for digester gas: 9,100 dscf/MMBtu (Estimated based on previous source tests and District practice)
- MMBtu/hr to bhp conversion 392.75 bhp-hr/MMBtu (per AP-42, Appendix A)

- Average sulfur content of the scrubbed digester gas: 40 ppmv as $H_2S$ (proposed by applicant)
- Molar Specific Volume = 379.5 scf/lb-mol (60°F)
- Molecular weights:
  - $NO_x$ (as $NO_2$) = 46 lb/lb-mol  CO = 28 lb/lb-mol  $NH_3$ = 17 lb/lb-mol
  - VOC (as $CH_4$) = 16 lb/lb-mol  $SO_x$ (as $SO_2$) = 64.06 lb/lb-mol
- Efficiency of engine = 30% (District practice)
- A commissioning period to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system or oxidation catalyst will be allowed during initial startup of the engine. The duration of the commissioning period shall last no more than 120 hours of operation of the engine without the SCR system or oxidation catalyst installed and operating at its maximum efficiency (proposed by applicant)
- During normal operation the engine will operate 24 hours/day and 8,500 hours per year (proposed by the applicant)
- Ammonia slip from SCR = 10 ppm (proposed by applicant)

## B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent its damage. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[1] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

[1] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/ttn/atw/rice/20120717riceqaupdate.pdf)

| Emission Factors for Digester Gas-Fired Engine (Commissioning Period) | | | |
|---|---|---|---|
| **Pollutant** | **g/bhp·hr** | **ppmvd (@ 15%$O_2$)** | **Source** |
| NOx | 1.0 | -- | Information from Engine Supplier (Caterpillar) |
| SOx | 0.04 | 40 ppmvd in fuel gas | BACT Requirement/Mass Balance Equation on the Following Page |
| $PM_{10}$ | 0.08 | -- | AP-42, Table 2.4-4, October 2008, See Equation on the Following Page |
| CO | 4.4 | -- | Information from Engine Supplier (Caterpillar) |
| VOC | 1.1 | -- | Information from Engine Supplier (Caterpillar) |
| $NH_3$ | 0.06 | 10 ppmvd | Proposed by the Applicant, See Conversion on the Following Page |

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NOx, CO, and VOC from the proposed engine during normal operation were proposed by the applicant and supported by information provided by the engine and catalyst supplier. The emission factors for NOx, CO, and VOC will be achieved with the use of the SCR and catalyst system. The emission factors for SOx, $PM_{10}$, and ammonia slip during normal operation are the same as the emission factors presented above for during the commissioning period. The unit conversions (from ppmvd to g/bhp-hr) for the emission factors are also shown below.

| Emission Factors for Digester Gas-Fired Engine (Normal Operation) | | | |
|---|---|---|---|
| **Pollutant** | **g/bhp·hr** | **ppmvd (@ 15%$O_2$)** | **Source** |
| NOx | 0.15 | 10 ppmvd | Proposed by the Applicant, See Conversion Below |
| SOx | 0.04 | 40 ppmvd in fuel gas | Proposed by the Applicant, See Equation on the Following Page |
| $PM_{10}$ | 0.08 | -- | AP-42, Table 2.4-4, October 2008, See Conversion on the Following Page |
| CO | 2.0 | 223 ppmvd | Proposed by the Applicant, See Conversion on the Following Page |
| VOC | 0.10 | 20 ppmvd | Proposed by the Applicant, See Conversion on the Following Page |
| $NH_3$ | 0.06 | 10 ppmvd | Proposed by the Applicant, See Conversion on the Following Page |

NOx – 10 ppmvd @ 15% $O_2$ as proposed by the Applicant

$$\frac{10\ \text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{1\text{MMBtu}} \times \frac{46\ \text{lb NOx}}{1\ \text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\ \text{lb-mole}}{379.5\ \text{ft}^3} \times \frac{\text{MMBtu}}{392.75\ \text{bhp-hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.15\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

SOx – 40 ppmvd $H_2S$ @ 15% $O_2$ in fuel gas

$$\frac{40\ ft^3\ H_2S}{10^6\ ft^3} \times \frac{32.06\ lb\ S}{lb\text{-}mol\ H_2S} \times \frac{lb\text{-}mole}{379.5\ ft^3} \times \frac{64.06\ lb\ SO_2}{32.06\ lb\ S} \times \frac{ft^3}{700\ Btu} \times \frac{10^6\ Btu}{MMBtu} = 0.00965\ \frac{lb\ SOx}{MMBtu}$$

$$0.00965\ \frac{lb\ SOx}{MMBtu} \times \frac{MMBtu}{392.75\ bhp\text{-}hr} \times \frac{Btu_{in}}{0.30\ Btu_{out}} \times \frac{453.59\ g}{lb} = 0.04\ \frac{g\text{-}SOx}{bhp\text{-}hr}$$

$PM_{10}$ – AP-42, Table 2.4-4: 15 lb/$10^6$ dscf

15 lb-$PM_{10}$/$10^6$ dscf x 1 scf/ 700 Btu = 0.021 lb/MMBtu

$$0.021\ \frac{lb\ PM10}{MMBtu} \times \frac{1\ MMBtu}{10^6\ Btu} \times \frac{Btu_{in}}{0.30\ Btu_{out}} \times \frac{2{,}545\ Btu}{hp\text{-}hr} \times \frac{453.59\ g}{lb} = 0.08\ \frac{g\text{-}PM10}{bhp\text{-}hr}$$

CO – 223 ppmvd @ 15% O2

$$\frac{223\ ft^3\ CO}{10^6\ ft^3} \times \frac{9{,}100\ ft^3}{1\ MMBtu} \times \frac{28\ lb\ CO}{1\ lb\text{-}mole} \times \frac{20.9}{20.9-15} \times \frac{1\ lb\text{-}mole}{379.5\ ft^3} \times \frac{MMBtu}{392.75\ bhp\text{-}hr} \times \frac{453.6\ g}{lb} \times \frac{Btu_{in}}{0.30\ Btu_{out}} = 2.0\ \frac{g\text{-}CO}{bhp\text{-}hr}$$

VOC – 20 ppmvd @ 15% $O_2$ as proposed by the Applicant

$$\frac{20\ ft^3\ VOC}{10^6\ ft^3} \times \frac{9{,}100\ ft^3}{1\ MMBtu} \times \frac{16\ lb\ VOC}{1\ lb\text{-}mole} \times \frac{20.9}{20.9-15} \times \frac{1\ lb\text{-}mole}{379.5\ ft^3} \times \frac{MMBtu}{392.75\ bhp\text{-}hr} \times \frac{453.6\ g}{lb} \times \frac{Btu_{in}}{0.30\ Btu_{out}} = 0.10\ \frac{g\text{-}VOC}{bhp\text{-}hr}$$

$NH_3$ – 10 ppmvd @ 15% $O_2$ as proposed by the Applicant

$$\frac{10\ ft^3\ NH_3}{10^6\ ft^3} \times \frac{9{,}100\ ft^3}{MMBtu} \times \frac{17\ lb\ NH_3}{lb\text{-}mole} \times \frac{20.9}{20.9-15} \times \frac{1\ lb\text{-}mole}{379.5\ ft^3} \times \frac{MMBtu}{392.75\ bhp\text{-}hr} \times \frac{453.6\ g}{lb} \times \frac{Btu_{in}}{0.30\ Btu_{out}} = 0.06\ \frac{g\text{-}NH_3}{bhp\text{-}hr}$$

**C. Calculations**

**1. Pre-Project Potential to Emit (PE1)**

Since this is a new emissions unit, PE1 = 0 for all pollutants.

**2. Post-Project Potential to Emit (PE2)**

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

| Daily PE2 During the Commissioning Period | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_x$ | 1.0 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 69.1 | (lb/day) |
| $SO_x$ | 0.04 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 2.8 | (lb/day) |
| $PM_{10}$ | 0.08 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 5.5 | (lb/day) |
| CO | 4.4 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 304.0 | (lb/day) |
| VOC | 1.1 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 76.0 | (lb/day) |
| $NH_3$ | 0.06 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 4.1 | (lb/day) |

Daily PE2 for the Engine after Completion of the Commissioning Period:

Daily PE for the proposed engine after completion of the commissioning period is calculated in the table below:

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

| Daily PE2 After the Commissioning Period (Normal Operation) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_x$ | 0.15 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 10.4 | (lb/day) |
| $SO_x$ | 0.04 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 2.8 | (lb/day) |
| $PM_{10}$ | 0.08 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 5.5 | (lb/day) |
| CO | 2.0 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 138.2 | (lb/day) |
| VOC | 0.10 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 6.9 | (lb/day) |
| $NH_3$ | 0.06 | (g/bhp·hr) x | 1,306 | (bhp) x | 24 | (hr/day) ÷ 453.6 (g/lb) = | 4.1 | (lb/day) |

Maximum Annual PE2 for the Engine Including the Commissioning Period:

As discussed above, the proposed engine will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for the engine will be calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

| Annual PE2 During the Commissioning Period | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_x$ | 1.0 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 346 | (lb/yr) |
| $SO_x$ | 0.04 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 14 | (lb/yr) |
| $PM_{10}$ | 0.08 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 28 | (lb/yr) |
| CO | 4.4 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 1,520 | (lb/yr) |
| VOC | 1.1 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 380 | (lb/yr) |
| $NH_3$ | 0.06 | (g/bhp·hr) x | 1,306 | (bhp) x | 120 | (hr/yr) ÷ 453.6 (g/lb) = | 21 | (lb/yr) |

| First Year Annual PE2 After the Commissioning Period | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| $NO_x$ | 0.15 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 3,619 | (lb/yr) |
| $SO_x$ | 0.04 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 965 | (lb/yr) |
| $PM_{10}$ | 0.08 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 1,930 | (lb/yr) |
| CO | 2.0 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 48,255 | (lb/yr) |
| VOC | 0.10 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 2,413 | (lb/yr) |
| $NH_3$ | 0.06 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,380 | (hr/yr) ÷ | 453.6 (g/lb) = | 1,448 | (lb/yr) |

Maximum Annual PE2 from the Engine during 1st year, Including Commissioning:

| Maximum Post-Project Daily and Annual PE2 | | | | |
|---|---|---|---|---|
| Pollutant | Daily (lb/day) | During Commissioning (lb/year) | After Commissioning (lb/year) | Total (lb/year) |
| $NO_x$ | 69.1 | 346 | 3,619 | 3,965 |
| $SO_x$ | 2.8 | 14 | 965 | 979 |
| $PM_{10}$ | 5.5 | 28 | 1,930 | 1,958 |
| CO | 304.0 | 1,520 | 48,255 | 49,775 |
| VOC | 76.0 | 380 | 2,413 | 2,793 |
| $NH_3$ | 4.1 | 21 | 1,448 | 1,469 |

Annual PE2 for the Engine in years with no Commissioning:

The annual PE2 for the engine after completion of the first year of operation when there will not be any commissioning period is calculated as follows:

| Annual PE2 After Year 1 with no Commissioning (Normal Operation) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| $NO_x$ | 0.15 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 3,671 | (lb/yr) |
| $SO_x$ | 0.04 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 979 | (lb/yr) |
| $PM_{10}$ | 0.08 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 1,958 | (lb/yr) |
| CO | 2.0 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 48,946 | (lb/yr) |
| VOC | 0.10 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 2,447 | (lb/yr) |
| $NH_3$ | 0.06 | (g/bhp·hr) x | 1,306 | (bhp) x | 8,500 | (hr/yr) ÷ | 453.6 (g/lb) = | 1,468 | (lb/yr) |

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site. Pursuant to the applicant, the digester gas operation permitted under ATC C-9133-2-0 will be implemented and should be included in the SSPE1 calculation; however, as calculated in project C-1170074, the PE2 for the digester gas operation is 0 lb/year. Therefore, SSPE1 = 0 lb/year for all pollutants.

## 4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

| SSPE2 (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| **Permit Unit** | **$NO_X$** | **$SO_X$** | **$PM_{10}$** | **CO** | **VOC** | **$NH_3$** |
| C-9133-2-0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C-9133-3-0 | 3,965 | 979 | 1,958 | 49,775 | 2,793 | 1,469 |
| **SSPE2** | **3,965** | **979** | **1,958** | **49,775** | **2,793** | **1469** |

## 5. Major Source Determination

<u>**Rule 2201 Major Source Determination:**</u>

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

| Rule 2201 Major Source Determination (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| | **$NO_X$** | **$SO_X$** | **$PM_{10}$** | **$PM_{2.5}$** | **CO** | **VOC** |
| SSPE1 | 0 | 0 | 0 | 0 | 0 | 0 |
| SSPE2 | 3,965 | 979 | 1,958 | 1,958 | 49,775 | 2,793 |
| Major Source Threshold | 20,000 | 140,000 | 140,000 | 140,000 | 200,000 | 20,000 |
| Major Source? | No | No | No | No | No | No |

Note: $PM_{2.5}$ assumed to be equal to $PM_{10}$

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

**Rule 2410 Major Source Determination:**

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

| PSD Major Source Determination (tons/year) | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | VOC | $SO_2$ | CO | PM | $PM_{10}$ |
| Estimated Facility PE before Project Increase | 0 | 0 | 0 | 0 | 0 | 0 |
| PSD Major Source Thresholds | 250 | 250 | 250 | 250 | 250 | 250 |
| PSD Major Source? | No | No | No | No | No | No |

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

## 6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

## 7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

## 8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification.

## 9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)

### I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

| PSD Major Source Determination: Potential to Emit (tons/year) | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_2$ | VOC | $SO_2$ | CO | PM | $PM_{10}$ |
| Total PE from New and Modified Units | 2.0 | 1.4 | 0.5 | 24.9 | 1.0 | 1.0 |
| PSD Major Source threshold | 250 | 250 | 250 | 250 | 250 | 250 |
| New PSD Major Source? | N | N | N | N | N | N |

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

### 10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix E.

## VIII. Compliance Determination

## Rule 2201 New and Modified Stationary Source Review Rule

### A. Best Available Control Technology (BACT)

#### 1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

#### a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the proposed engine will have a PE greater than 2.0 lb/day for $NO_x$, $SO_x$, $PM_{10}$, CO, and VOC. Therefore, BACT is triggered for $NO_x$, $SO_x$, $PM_{10}$, and VOC. However, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The proposed engine will have a PE greater than 2.0 lb/day for NH3. However, NH3 slip emissions are the result from operation of an emissions control device (SCR) and not the emissions unit; therefore, this project does not trigger BACT for NH3 emissions.

#### b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

### c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

### d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification for any pollutant. Therefore BACT is not triggered for any pollutant.

## 2. BACT Guideline

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engine. [Waste Gas-Fired IC Engines] (See Appendix B)

## 3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the Top-Down BACT Analysis (See Appendix C), BACT has been satisfied with the following:

$NO_X$: $NO_X$ emissions ≤ 0.15 g/bhp-hr
$SO_X$: Fuel sulfur content ≤ 40 ppmv (as $H_2S$)
$PM_{10}$: Fuel sulfur content ≤ 40 ppmv (as $H_2S$)
VOC: VOC emissions ≤ 0.10 g/bhp-hr

The following conditions will be placed on the ATC to ensure compliance with the BACT requirements during normal operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

## B. Offsets

### 1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

| Offset Determination (lb/year) | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| SSPE2 | 3,965 | 979 | 1,958 | 49,775 | 2,793 |
| Offset Thresholds | 20,000 | 54,750 | 29,200 | 200,000 | 20,000 |
| Offsets triggered? | No | No | No | No | No |

### 2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

## C. Public Notification

### 1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification

#### a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

**b. PE > 100 lb/day**

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

| PE > 100 lb/day Public Notice Thresholds | | | |
|---|---|---|---|
| **Pollutant** | **PE2 (lb/day)** | **Public Notice Threshold** | **Public Notice Triggered?** |
| $NO_X$ | 69.1 | 100 lb/day | No |
| $SO_X$ | 2.8 | 100 lb/day | No |
| $PM_{10}$ | 5.5 | 100 lb/day | No |
| CO | 304.0 | 100 lb/day | Yes |
| VOC | 76.0 | 100 lb/day | No |
| $NH_3$ | 4.1 | 100 lb/day | No |

Therefore, public noticing for PE > 100 lb/day purposes is required.

**c. Offset Threshold**

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

| Offset Thresholds | | | | |
|---|---|---|---|---|
| **Pollutant** | **SSPE1 (lb/year)** | **SSPE2 (lb/year)** | **Offset Threshold** | **Public Notice Required?** |
| $NO_X$ | 0 | 3,965 | 20,000 lb/year | No |
| $SO_X$ | 0 | 979 | 54,750 lb/year | No |
| $PM_{10}$ | 0 | 1,958 | 29,200 lb/year | No |
| CO | 0 | 49,775 | 200,000 lb/year | No |
| VOC | 0 | 2,793 | 20,000 lb/year | No |

As demonstrated above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

### d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

| SSIPE Public Notice Thresholds | | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **SSPE2 (lb/year)** | **SSPE1 (lb/year)** | **SSIPE (lb/year)** | **SSIPE Public Notice Threshold** | **Public Notice Required?** |
| $NO_x$ | 3,965 | 0 | 3,965 | 20,000 lb/year | No |
| $SO_x$ | 979 | 0 | 979 | 20,000 lb/year | No |
| $PM_{10}$ | 1,958 | 0 | 1,958 | 20,000 lb/year | No |
| CO | 49,775 | 0 | 49,775 | 20,000 lb/year | Yes |
| VOC | 2,793 | 0 | 2,793 | 20,000 lb/year | No |
| $NH_3$ | 1,469 | 0 | 1,469 | 20,000 lb/year | No |

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

### e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

## 2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions in excess of 100 lb/day and SSIPE greater than 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

## D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

***Proposed Rule 2201 (DEL) Conditions***

Proposed Rule 2201 (DEL) Conditions for Engine during Both Commissioning and Normal Operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as $H_2S$. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit.[2] [District Rules 2201, 4102, 4702, and 4801]
- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
- Ammonia ($NH_3$) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
- All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For the proposed engine, the DELs for $NO_X$, $SO_X$, $PM_{10}$, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,306 bhp), and maximum number of hours allowed for commissioning activities. The following conditions will be placed on the permit as a mechanism to ensure compliance.

- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- Commissioning activities are defined as, but not limited to, all adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

[2] Due to variations in sulfur content of the digester gas, an averaging time cannot be established until the unit has operated in a steadystate manner.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-$PM_{10}$/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
- The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system and oxidation catalyst, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system and oxidation catalyst. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

  Additionally, to limit annual emissions, the following condition will be included on the ATC:

- This engine shall not operate more than 8,500 hours per calendar year. [District Rule 2201]

## E. Compliance Assurance

### 1. Source Testing

In accordance with District Policy APR 1705, source testing for $NO_x$, CO and VOC emissions from the digester gas fired IC engine served by a catalyst control system (including SCR and an oxidation catalyst) shall be conducted initially and at least once every 24 months thereafter. In addition, in order to assure compliance with the ammonia slip limit from the SCR system, source testing of the ammonia emissions will also be required initially and at least once every 24 months thereafter.

For $PM_{10}$ emissions, the applicant has proposed to use an emission factor from AP-42, Section 2.4, which is applicable to municipal solid waste landfills. The digester gas fired in this engine should have a similar makeup to that of gas generated by a landfill. However, in order to assure that the engine is able to demonstrate compliance with the proposed $PM_{10}$ emission factor, initial source testing will be required.

The engine is not served by any control devices for $PM_{10}$ emissions. Therefore, it is not expected that the $PM_{10}$ emissions will change much over time as long as the quality of the gas combusted in this unit remains fairly consistent. The facility will be required to monitor the sulfur content of the digester gas combusted in this unit at least once per quarter. The results of this quarterly monitoring should demonstrate that the quality of the gas combusted is consistent. Therefore, ongoing periodic source testing for $PM_{10}$ emissions will not be required.

The following conditions will be placed on the permit to ensure compliance:

- Source testing to measure $NO_x$, CO, VOC, $PM_{10}$, and ammonia ($NH_3$) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
- Source testing to measure $NO_x$, CO, VOC, and ammonia ($NH_3$) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and $NH_3$ concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for emissions source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, ARB Method 5 (front half and back half), or ARB Method 5 (front half and back half) in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

## 2. Monitoring

The proposed digester gas-fired engine is subject to District Rule 4702 - Internal Combustion Engines. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of $NO_X$ emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. However, Section 6.5.3 of District Rule 4702 requires monthly monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. Therefore, monthly monitoring of $NO_X$, CO, and $O_2$ concentrations in accordance pre-approved alternate monitoring plan "A" will be required. Since the engine will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of $NO_x$, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- The permittee shall monitor and record the stack concentration of $NH_3$ at least once every calendar quarter in which a source test is not performed. $NH_3$ monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or $NH_3$ concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the allowable emission concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 8 hours, the permittee shall notify the District within the following 1 hour, and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. Because of the variable content of digester gas, additional monitoring of the fuel sulfur content will be required.

The following conditions will be placed on the permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of

the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rules 2201 and 4702]

- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rules 2201 and 4702]

### 3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following recordkeeping conditions will be listed on the permit:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
- The permittee shall maintain records of: (1) the date and time of $NO_x$, CO, O2, and $NH_3$ measurements, (2) the O2 concentration in percent and the measured NOx, CO, and $NH_3$ concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rule 2201]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]
- Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]
- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201
- {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

**4. Reporting**

No reporting is required to demonstrate compliance with Rule 2201.

**F. Ambient Air Quality Analysis (AAQA)**

Section 4.14 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix D of this document for the AAQA summary sheet.

The proposed location is in an attainment area for $NO_x$, CO, and $SO_x$. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for $NO_x$, CO, or $SO_x$.

The proposed location is in a non-attainment area for the state's $PM_{10}$ as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for $PM_{10}$ and $PM_{2.5}$.

**Rule 2410 Prevention of Significant Deterioration**

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

**Rule 2520 Federally Mandated Operating Permits**

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

**Rule 4001 New Source Performance Standards (NSPS)**

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

**40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines**

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of $NO_x$, $SO_x$, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The engine is a 1,306 bhp SI ICE that was constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engine is subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

**Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)**

This rule incorporates NESHAPs from Part 63, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 63.

**40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines**

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part.

As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the permit. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

**Rule 4101 Visible Emissions**

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

Since the engine is fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**Rule 4102 Nuisance**

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

The following nuisance prohibition condition will be included on the permits:

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**California Health & Safety Code 41700 (Health Risk Assessment)**

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

| HRA Summary | | |
|---|---|---|
| **Unit** | **Cancer Risk** | **T-BACT Required** |
| C-9133-3-0 | 0.0823 per million | No |

**Discussion of T-BACT**

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix D of this report, the emissions increases for this project was determined to be less than significant.

The following condition will be listed on the permit as a mechanism to ensure compliance.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

**Rule 4201 Particulate Matter Concentration**

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. The higher of the two emission factors (0.08 g-$PM_{10}$/bhp-hr and 0.03 g-$PM_{10}$/bhp-hr) for the engine will be used to demonstrate compliance for the engine:

$$\frac{0.08\ \text{g}}{\text{hp}\cdot\text{hr}} \times \frac{1\ \text{hp}\cdot\text{hr}}{2{,}545\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{9{,}100\ \text{dscf}} \times \frac{0.3\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{15.43\ \text{grain}}{\text{g}} = 0.02\ \ \frac{\text{grain}}{\text{dscf}}$$

Since 0.02 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the permits as a mechanism to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**Rule 4701 Internal Combustion Engines – Phase I**

The purpose of this rule is to limit the emissions of nitrogen oxides ($NO_x$), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion (IC) engines.

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

**Rule 4702 Internal Combustion Engines**

The purpose of this rule is to limit the emissions of nitrogen oxides ($NO_x$), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides ($SO_x$) from IC engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0.

The engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the engine.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 $NO_x$, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 $SO_x$ control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and
5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the $NO_x$ emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. As shown below, the applicant is proposing to comply with the $NO_x$ emission limit requirement of Table 2 as required by Section 5.2.2.1.1; therefore, no further discussion is required.

Section 5.2.2.3 allows that in lieu of complying with the NOx, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. As shown below, the applicant is proposing to comply with the NOx, CO, and VOC emission limit requirements of Table 2; therefore, no further discussion is required.

| **Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations** (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.) | | | |
|---|---|---|---|
| **Engine Type** | **NOx Emission Limit (ppmv @ 15% $O_2$, dry)** | **CO Emission Limit (ppmv @ 15% $O_2$, dry)** | **VOC Emission Limit (ppmv @ 15% $O_2$, dry)** |
| 2. e. Lean-Burn, Not Listed Above | 11 ppmv | 2,000 ppmv | 750 ppmv |

The engine is operated as a separate stationary source on land leased from an existing dairy, and the District has determined that the engine is a non-agricultural IC engine. The engine is fired on digester gas which does not satisfy the definition of waste gas; therefore, the engine is required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NOx, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% $O_2$).

Therefore, the following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3 applies to spark-ignited engines used exclusively in agricultural operations. As stated above, the engine is operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the engine.

Section 5.2.4 applies to certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.4 does not apply to the engine.

Section 5.2.5 applies to non-certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.5 does not apply to the engine.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The engine does not have CEMS installed; therefore this section of the rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NOx emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NOx emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the engine complies with the applicable emission limits of Table 2 of District Rule 4702; therefore, payment of annual emissions fees for the engine is not required and this section of the rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces $SO_2$ emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The average sulfur content of the digester gas fuel for the engine is limited to 40 ppmv or 0.04 g/bhp-hr (approximately equal to 0.008 grains sulfur per standard cubic feet[3]). The following condition will be listed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as $H_2S$. The applicant may utilize an averaging period of up to 24 hours in length for

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$$0.04 \quad \frac{g}{hp\cdot hr} \times \frac{39275 hp\cdot hr}{MMBtu} \times \frac{MMBtu}{9{,}100 dscf} \times \frac{0.30 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = 0.008 \quad \frac{grai}{dscf}$$

demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NOx and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,
5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NOx, CO, and $O_2$ emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The engine is subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The engine includes a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NOx, CO, and $O_2$ emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The engine does not have CEMS installed; therefore, this section of the rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the engine includes an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engine in this project. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the operator shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.8 requires that for each engine, the operator shall collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the operator shall use a portable NOx analyzer to take NOx emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NOx emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NOx emissions readings shall be reported to the APCO in a manner approved by the APCO. NOx emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The permit for the engine includes a pre-approved alternate emissions monitoring plan that requires periodic NOx, CO, and $O_2$ emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore this section of the rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The engine is subject to the requirements of Section 5.8; therefore this section of the rule is not applicable.

Section 5.10 specifies SOx Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The engine is required to have a District Permit to Operate; therefore this section of the rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.1.1.2 Engines subject to Section 8.0;

6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;

6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for the engines:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of $NO_x$, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engines are in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2. The applicant has submitted all the required information for Section 6.1 in the application for the engine evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. The applicant is not claiming an exemption for the engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Sections 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.

6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following condition will be included in the permit as a mechanism to ensure compliance:

- Source testing to measure NOx, CO, VOC, and ammonia ($NH_3$) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NOx emissions shall also be reported.

The following conditions will be included in the permit as a mechanism to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and $NH_3$ concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The engine is fueled by digester gas; therefore, this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engine; therefore, this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SOx Test Methods

6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.
6.4.6.2 Determination of total sulfur as hydrogen sulfide ($H_2S$) content – EPA Method 11 or EPA Method 15, as appropriate.
6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
6.4.6.4 The SOx emission control system efficiency shall be determined using the following:
% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$
Where:
$C_{SO2,\ inlet}$ = concentration of SOx (expressed as $SO_2$) at the inlet side of the SOx emission control system, in lb/Dscf
$C_{SO2,\ outlet}$ = concentration of SOx (expressed as $SO_2$) at the outlet side of the SOx emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.
6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the permit as a mechanism to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; $NH_3$ - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;
6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.
6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

The engine is equipped with an SCR system for control of NOx and oxidation catalyst for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engine.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engine is operated and maintained per the manufacturer's specifications.

Section 6.5.7 requires procedures and a schedule for using a portable NOx analyzer to take NOx emission readings pursuant to Section 5.8.9.

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO.

*NOx Emissions:*

In order to satisfy the I&M requirements for NOx emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic NOx emission concentration measurements with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and NOx emissions. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall be imposed as a condition in the Permit to Operate. [District Rule 4702]
- If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

- The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or $NH_3$ concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

In order to satisfy the I&M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic CO emission concentration measurements with a portable analyzer at least once every calendar quarter. Per the catalyst manufacturer, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, quarterly emission concentration measurements with a portable analyzer for VOC emissions will not be required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emission concentration measurements, the applicant proposed to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure. The appropriate ranges for each operating load were established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate [District Rule 4702]
- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the

dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed to comply with the I&M plan modification requirements per this section of the rule. The following condition will be listed on the permit as a mechanism to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The engine was required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NOx emission requirements of Section 5.2 for a group of engines. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore, this section of the rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the proposed engine is not currently being proposed; therefore, this section of the rule is not applicable at this time.

Conclusion

As shown above, the engine satisfies all the requirements of Rule 4702. The following conditions will be added to the permit as a mechanism to ensure continued compliance:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

**Rule 4801 Sulfur Compounds**

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as $SO_2$) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of $SO_x$ as ($SO_2$) = (n x R x T) ÷ P

Where:

n = moles $SO_x$
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the engine will be calculated using the maximum sulfur content allowed for the digester gas, which is 40 ppmv, equivalent to 0.00965 lb-SOx/MMBtu.

$$0.00965\ \frac{lb}{MMBtu}\times\frac{1\,MMBtu}{9{,}100\,scf_{exhaust}}\times\frac{1\,lb\cdot mol}{64\,lb\cdot SO_2}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times 1{,}000{,}000\,ppm = 6.29\ \text{ppmv}$$

Since 6.29 ppmv is ≤ 2000 ppmv, the engine is expected to comply with Rule 4801. The following condition will be placed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

**California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Environmental Quality Act (CEQA)**

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

**Greenhouse Gas (GHG) Significance Determination**

It is determined that no other agency has prepared or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for installation of an IC engine that will combust dairy digester gas to produce electricity. The digester system at this facility diverts manure from an adjacent dairy to covered lagoon digester(s), which will result in the capture of the methane that would otherwise be released into the atmosphere from open basin(s)/pond(s) at the dairy. Combustion of the dairy digester gas in the engine will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digester(s) will result in a large net decrease in the global warming potential emitted from the dairy when compared to uncontrolled levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

**District CEQA Findings**

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing or former use. Furthermore, the District determined that the activity will not have a significant effect on the environment. Therefore, the District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

**Indemnification Agreement/Letter of Credit Determination**

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

## IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATC C-9133-3-0 subject to the permit conditions on the attached draft ATC in Appendix A.

## X. Billing Information

| Annual Permit Fees | | | |
|---|---|---|---|
| **Permit Number** | **Fee Schedule** | **Fee Description** | **Annual Fee** |
| C-9133-3-0 | 3020-10-F | 1,306 bhp IC engine | $900.00 |

**Appendixes**

A: Draft ATC
B: BACT Guideline
C: BACT Analysis
D: RMR and AAQA Summary
E: Quarterly Net Emissions Change

# APPENDIX A
## Draft ATC

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** C-9133-3-0 **ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** LONE OAK ENERGY LLC
**MAILING ADDRESS:** 2911 HANFORD ARMONA RD
HANFORD, CA 93230

**LOCATION:** 10014 S MCMULLIN GRDE
FRESNO, CA 93706

**EQUIPMENT DESCRIPTION:**
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

## CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services

C-9133-3-0 : Jan 21 2020 6:32PM -- GARCIAJ : Joint Inspection NOT Required

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]
11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]
15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]
22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]
24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
25. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

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CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

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CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]



CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

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# APPENDIX B
## BACT Guideline

# SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*
Last Update: 3/6/2013

## Waste Gas-Fired IC Engine**

| Pollutant | Achieved in Practice or contained in SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| $NO_x$ | 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) | | 1. Fuel Cells (<0.05 lb/MW-hr)<br>2. Microturbines (<9 ppmv @ 15% $O_2$)<br>3. Gas Turbine (<9 ppmv @ 15% $O_2$) *(Note: gas turbines only ABE for projects ≥ 3 MW)* |
| $SO_x$ | Sulfur content of fuel gas ≤ 40 ppmv (as $H_2S$) (dry absorption, wet absorption, chemical $H_2S$ reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance) | | |
| $PM_{10}$ | Sulfur content of fuel gas ≤ 40 ppmv (as $H_2S$) | | |
| CO | 2.0 g/bhp-hr | | 1. Fuel Cells (<0.10 lb/MW-hr)<br>2. Microturbines (<60 ppmv @ 15% $O_2$)<br>3. Gas Turbine (<60 ppmv @ 15% $O_2$) *(Note: gas turbines only ABE for projects ≥ 3 MW)* |
| VOC | 0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent) | | Fuel Cells (<0.02 lb-VOC/MW-hr as $CH_4$) |

** *For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

# APPENDIX C
## BACT Analysis

## Top-Down BACT Analyses for the Digester Gas-Fired Engine

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed engine.

### I. BACT Analysis for NOx Emissions:

#### a. Step 1 - List all control technologies

1) NOx emissions ≤ 0.15 g/bhp-hr = 10 ppmv NOx @ 15% $O_2$[4] (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

2) Fuel Cell (≤ 0.05 lb/MW-hr = 1.1 ppmv NOx @ 15% $O_2$[5]) (Alternate Basic Equipment)

3) Microturbine (< 9 ppmv NOx @ 15% $O_2$) (Alternate Basic Equipment)

4) Gas Turbine (< 9 ppmv NOx @ 15% $O_2$) (Alternate Basic Equipment)

Description of Control Technologies

**1) NOx emissions ≤ 0.15 g/bhp-hr (10 ppmv NOx @ 15% $O_2$) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)**

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NOx, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

**2) Fuel Cell (≤ 0.05 lb- NOx/MW-hr) (Alternate Basic Equipment)**

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and

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4 $$\frac{0.15\ \text{g NOx}}{\text{bhp - hr}} \times \frac{\text{MMBtu}}{9{,}100\ \text{dscf}} \times \frac{30\%}{1} \times \frac{1\ \text{lb - mol}}{46\ \text{lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\ \text{dscf}}{1\ \text{lb mol}} \times \frac{393.75\ \text{bhp - hr}}{\text{MMBtu}} \times \frac{\text{lb}}{453.6\ \text{g}} = 10\ \text{ppmv} @ 15\ \%\ \text{O2}$$

5 $$\frac{0.05\ \text{lb NOx}}{\text{MW - hr}} \times \frac{\text{MW}}{1{,}341\ \text{bhp}} \times \frac{\text{MMBtu}}{9{,}100\ \text{dscf}} \times \frac{30\%}{1} \times \frac{1\ \text{lb - mol}}{46\ \text{lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\ \text{dscf}}{1\ \text{lb mol}} \times \frac{393.75\ \text{bhp - hr}}{\text{MMBtu}} = 1.1\ \text{ppmv} @ 15\ \%\ \text{O2}$$

solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of $CO_2$ that is found in digester gas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for digester gas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, digester gas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

**3) Gas Turbine (< 9 ppmv $NO_x$ @ 15% $O_2$) (Alternate Basic Equipment)**

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, $NO_x$ emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for digester gas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, digester gas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller digester gas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

**4) Microturbine (< 9 ppmv $NO_x$ @ 15% $O_2$) (Alternate Basic Equipment)**

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 digester gas-fired microturbines operating in

California as of the year 2006.[6] Microturbines generally have electrical efficiencies of 25 - 30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30 - 33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of $NO_x$, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low $NO_x$, or DLN) combustion technology. Microturbines manufacturers will generally guarantee $NO_x$ emissions of 9 - 15 ppmv @ 15% $O_2$. However, several emission tests performed on digester gas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[7], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 5) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. In addition, a different applicant for digester gas projects recently permitted by the District (Projects S-1143770 and S-1143771) indicated that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

**b. Step 2 - Eliminate technologically infeasible options**

Option 3 - Gas Turbine (≤ 9 ppmv $NO_x$ @ 15% $O_2$) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine

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[6] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)
[7] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[8] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[9] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

The proposed project would require a gas turbine rated 1,028 kW, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

**c. Step 3 - Rank remaining options by control effectiveness**

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NOx @ 15% $O_2$) (Alternate Basic Equipment)

2) Digester gas-fueled microturbines (Alternate Basic Equipment)

3) NOx emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engine is a non-agricultural IC engine. The lean burn, digester gas-fired, engine is subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.e: 11 ppmvd NOx (or 0.17 g/bhp-hr)[10], 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% $O_2$). The proposed digester gas-fired digester engine is also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% $O_2$ reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engine will be based on the emission limits contained in these applicable regulations.

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$$\frac{11\,\text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{1\,\text{MMBtu}} \times \frac{46\ \text{lb NOx}}{1\ \text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\ \text{lb-mole}}{379.5\ \text{ft}^3} \times \frac{\text{MMBtu}}{392.75\ \text{bhp-hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{in}}{0.30\ \text{Btu}_{out}} = 0.17\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)

Because fuel cells have reduced $NO_X$ and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis will examine if the replacement of the proposed engine with a fuel cell is cost effective even when the additional operation costs of a fuel cell are not considered.

**Assumptions**

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 700 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[11] *beginning June 1, 2016*)
- MMBtu/hr to bhp conversion: 392.75 (per AP-42, Appendix A)
- Btu to kW-hr conversion: 3,413 Btu/kW-hr (per AP-42, Appendix A)
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and fuel cell will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of digester gas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [9]

Assumptions for the Proposed Digester Gas-Fired IC Engine

- The engine will operate at full load for 24 hours/day and 8,500 hours/year
- Typical thermal efficiencies for IC engines range from 30-35%. A worst case thermal efficiency of 30% will be used.
- The maximum total daily heating value of the digester gas used by the engine will be: 266.02 MMBtu/day (*1,306 $bhp_{out}$/engine x 1 $bhp_{in}$/0.30 $bhp_{out}$ x 1 $MMBtu_{in}$/ 392.75 $bhp_{in}$-hr x 24 hr/day*)
- The maximum total annual heating value for of the digester gas used by the engine will be: 94,216 MMBtu/year (*1,306 $bhp_{out}$/engine x 1 $bhp_{in}$/0.30 $bhp_{out}$ 1 $MMBtu_{in}$/ 392.75 $bhp_{in}$-hr x 8,500 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,028 kW without add-on air pollution control equipment: $1,223/kW (*average of interpolated*

11 See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

*values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-15 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)

- Additional capital investment for digester gas conditioning and cleanup for the engine: \$387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester-fueled IC engine rated 1,028 kW: \$1,610/kW
- Estimated operation costs for CHP IC engine rated 1,028 kW without add-on air pollution control costs: \$0.028/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-17 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that digester gas conditioning/cleanup costs are highly dependent on the quantity of digester gas being processed and contaminants being removed and that the differences in clean-up costs for digester gas-fired IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engine must be limited to a sulfur content of no more than 40 ppmv as $H_2S$ to satisfy BACT for $SO_X$. Because required level of sulfur removal is adequate for use in the engine, there will be no increase in operating costs related to cleaning the digester gas for use in the engine.
- Rule 4702 $NO_X$ emission limit for non-agricultural, lean burn IC engines: 11 ppmv @ 15% $O_2$ = 0.165 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% $O_2$ as $CH_4$ = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% $O_2$ reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace the proposed engine: 1,463 kW (estimated based on 266.02 MMBtu/day and 45% efficiency[12])
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: \$4,474/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies on page 6-16 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-13; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at:* <u>http://www.wbdg.org/resources/fuelcell.php)</u>

12 $$\frac{266.02\ \text{MMBtu}}{\text{day}} \times \frac{\text{kW-hr}}{3{,}410\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} \times \frac{\text{day}}{24\ \text{hrs}} \times 45\% = 1{,}463\ \text{kW}$$

*states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".)*

- Additional capital investment for digester gas conditioning and cleanup for the fuel cell: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW (the larger the capacity, the cheaper the cost) will be used: $5,037/kW
- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: $0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for digester gas conditioning and cleanup for large fuel cells: $0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW(conservatively using the cheaper cost of the larger capacity fuel cell): $0.19/kW-hr
- Unlike the proposed engine, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engine with a fuel cell is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of the proposed IC engine with a fuel cell power plant is calculated as follows:

(1,463 kW x $5,037/kW) - (1,028 kW x $1,610/kW) = $5,714,051

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where:
$A$ = Annual Cost
$P$ = Present Value
$I$ = Interest Rate (10%)
$N$ = Equipment Life (10 years)

$$A = [\$5{,}714{,}051 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \textbf{\$931,390/year}$$

<u>Annual Costs</u>

<u>Annual Operation and Maintenance Cost</u>

The annual operation and maintenance costs for each option are calculated as follows:

<u>Proposed 1,028 kW IC Engine</u>

8,738,000 kW-hr/yr x $0.028/kW-hr = $244,664/year

<u>Fuel Cells (Alternate Equipment)</u>

12,435,500 kW-hr/yr x $0.19/kW-hr = $2,362,745/year

<u>Annual Costs of Increased Maintenance</u>

$2,362,745/yr - $244,664/yr = $2,118,081/year

<u>Total Increased Annual Costs for Fuel Cell as an Alternative to the Proposed Engine</u>

$931,390/year + $2,118,081/year = **$3,049,471/year**

<u>Emission Reductions</u>

<u>NOx and VOC Emission Factors</u>

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NOx emissions from the engine will be based on the NOx emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for VOC emissions from the engine will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions

0.165 lb-$NO_x$/MMBtu (11 ppmv $NO_x$ @ 15% $O_2$)
0.111 lb-VOC/MMBtu (75 ppmv VOC @ 15% $O_2$)

Emissions from Fuel Cells as Alternative Equipment

0.016 lb-$NO_x$/MMBtu (0.05 lb-$NO_x$/MW-hr)
0.006 lb-VOC/MMBtu (0.02 lb-VOC/MW-hr)

Emission Reductions

The Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

$NO_x$ Emission Reductions (11 ppmv @ 15% $O_2$ → 0.05 lb-$NO_x$/MW-hr)

94,216 MMBtu/year x (0.165 lb-$NO_x$/MMBtu – 0.016 lb-$NO_x$/MMBtu)
= 14,038 lb-$NO_x$/year (7.0 ton-$NO_x$/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)

94,216 MMBtu/year x (0.111 lb-VOC/MMBtu – 0.006 lb-VOC/MMBtu)
= 9,893 lb-VOC/year (4.9 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for $NO_x$ and VOC Reductions based on District Standard Emission Reductions

(7.0 ton-$NO_x$/year x $24,500/ton-$NO_x$) + (4.9 ton-VOC/year x $17,500/ton-VOC)
= **$257,250/year**

As shown above, the annualized capital cost of this alternate option ($3,049,471) exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the $NO_x$ and VOC emission reductions ($257,250). Therefore, this option is not cost effective and is being removed from consideration.

Options 2 and 3 – Microturbine and IC Engine with NOx Emissions ≤ 0.15 g/bhp-hr

The applicant is proposing a NOx limit of 0.08 g/bhp-hr. Since this proposed limit is lower than the remaining options, per District BACT Policy APR 1305, Section IX.D.1, a cost effectiveness analysis is not required and no further analysis is required.

### e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engine must be satisfied with the following: $NO_x$ emissions ≤ 0.15 g/bhp-hr

The applicant has proposed to use an SCR system for the digester gas-fired lean burn IC engine to limit $NO_x$ emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

## 2. BACT Analysis for $SO_x$ Emissions:

### a. Step 1 - Identify all control technologies

The following options were identified to reduce $SO_x$ emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as $H_2S$ (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

### b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

### c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as $H_2S$ (Achieved in Practice)

### d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

### e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for $SO_x$ emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as $H_2S$. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to $\leq$ 40 ppmv as $H_2S$. Therefore, the BACT requirements for $SO_x$ are satisfied.

## 3. BACT Analysis for $PM_{10}$ Emissions:

### a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engine. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and $CO_2$ (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly $H_2S$) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engine:

1) Sulfur Content of fuel ≤ 40 ppmv as $H_2S$ (Achieved in Practice)

### b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

### c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as $H_2S$ (Achieved in Practice)

### d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

### e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for $PM_{10}$ emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as $H_2S$. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to ≤ 40 ppmv as $H_2S$. Therefore, the BACT requirements for $PM_{10}$ are satisfied.

## 4. BACT Analysis for VOC Emissions:

### a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

### b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

### c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

### d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as $CH_4$) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the $NO_x$ and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the $NO_x$ and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

### e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engine is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed an IC engine with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

# APPENDIX D
## HRA and AAQA Summary

# San Joaquin Valley Air Pollution Control District
# Risk Management Review and Ambient Air Quality Analysis

| | |
|---|---|
| To: | Manuel Salinas – Permit Services |
| From: | Will Worthley – Technical Services |
| Date: | December 10, 2019 |
| Facility Name: | LONE OAK ENERGY LLC |
| Location: | 10014 S MCMULLIN GRDE, FRESNO |
| Application #(s): | C-9133-3-0 |
| Project #: | C-1193519 |

## 1. Summary

### 1.1 RMR

| Units | Prioritization Score | Acute Hazard Index | Chronic Hazard Index | Maximum Individual Cancer Risk | T-BACT Required | Special Permit Requirements |
|---|---|---|---|---|---|---|
| 3-0 | 13.88 | 0.37 | 0.02 | 8.23E-08 | No | Yes |
| **Project Totals** | 13.88 | 0.37 | 0.02 | 8.23E-08 | | |
| **Facility Totals** | >1 | 0.64 | 0.03 | 1.41E-07 | | |

### 1.2 AAQA

| Pollutant | Air Quality Standard (State/Federal) | | | | |
|---|---|---|---|---|---|
| | 1 Hour | 3 Hours | 8 Hours | 24 Hours | Annual |
| **CO** | Pass | | Pass | | |
| **$NO_x$** | Pass | | | | Pass |
| **$SO_x$** | Pass | Pass | | Pass | Pass |
| **PM10** | | | | Pass[3] | Pass[3] |
| **PM2.5** | | | | Pass[4] | Pass[4] |

Notes:
1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m³ for the 24-hour average concentration and 1 μg/m³ for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m³ for the 24-hour average concentration and 0.2 μg/m³ for the annual concentration.

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 3-0

1. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
2. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

## 2. Project Description

Technical Services received a request on December 4, 2019 to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -3-0: 1,306 BHP CATERPILLAR, MODEL G3516LE, DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING, MODEL COMBIKAT, CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

## 3. RMR Report

### 3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emissions for this Dairy Gas Fired internal combustion (2 Stroke Lean Burn, or 4 Stroke Lean Burn, or 4 Stroke Rich Burn) Engine were calculated using emission factors from 2000, AP 42, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources, Section 2: Natural Gas-Fired Reciprocating Engines and Dairy Biomethane characterization from 2009 report, Pipeline Quality Biomethane: North American Guidance Document for Introduction o f Dairy Waste Derived Biomethane Into Existing Natural Gas Networks.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| Source Process Rates | | | | | |
|---|---|---|---|---|---|
| **Unit ID** | **Process ID** | **Process Material** | **Process Units** | **Hourly Process Rate** | **Annual Process Rate** |
| 3 | 1 | Fuel Usage (Commissioning) | MMscf | 0.013 | 1.59 |
| 3 | 1 | NH3 (Commissioning) | Lbs | 0.15 | 19 |
| 3 | 2 | Fuel Usage (Non-Commissioning) | MMscf | 0.013 | 112.9 |
| 3 | 2 | NH3 (Non-Commissioning) | Lbs | 0.16 | 1327 |

| Point Source Parameters | | | | | | |
|---|---|---|---|---|---|---|
| **Unit ID** | **Unit Description** | **Release Height (m)** | **Temp. (°K)** | **Exit Velocity (m/sec)** | **Stack Diameter (m)** | **Vertical/ Horizontal/ Capped** |
| 3 | Digester Engine (Non-Comissioning Period) | 6.71 | 709 | 38.31 | 0.36 | Vertical |
| 3 | Digester Engine (Comissioning Period) | 6.71 | 709 | 38.31 | 0.36 | Vertical |

## 4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour $NO_2$ standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

| Monitoring Stations | | | | |
|---|---|---|---|---|
| **Pollutant** | **Station Name** | **County** | **City** | **Measurement Year** |
| CO | Tranquillity | Fresno | Fresno | 2016 |
| NOx | Fresno-Drummond | Fresno | Fresno | 2016 |
| PM10 | Fresno-Drummond | Fresno | Fresno | 2016 |
| PM2.5 | Tranquillity | Fresno | Fresno | 2016 |
| SOx | Fresno - Garland | Fresno | Fresno | 2016 |

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

| Emission Rates (lbs/hour) | | | | | | |
|---|---|---|---|---|---|---|
| **Unit ID** | **Process** | **NOx** | **SOx** | **CO** | **PM10** | **PM2.5** |
| 3 | 1 | 2.89 | 0.12 | 12.67 | 0.23 | 0.23 |

| Emission Rates (lbs/year) | | | | | | |
|---|---|---|---|---|---|---|
| **Unit ID** | **Process** | **NOx** | **SOx** | **CO** | **PM10** | **PM2.5** |
| 3 | 1 | 3,965 | 979 | 49,776 | 1,958 | 1,958 |

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

| Point Source Parameters | | | | | | |
|---|---|---|---|---|---|---|
| **Unit ID** | **Unit Description** | **Release Height (m)** | **Temp. (°K)** | **Exit Velocity (m/sec)** | **Stack Diameter (m)** | **Vertical/ Horizontal/ Capped** |
| 3 | Digester Engine | 6.71 | 709 | 38.31 | 0.36 | Vertical |

## 5. Conclusion

### 5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

### 5.2 AAQA

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

## 6. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

E. AAQA results

# APPENDIX E
## Quarterly Net Emissions Change (QNEC)

**Quarterly Net Emissions Change (QNEC)**

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

| Quarterly NEC [QNEC] | | | |
|---|---|---|---|
| **Pollutant** | **PE2 (lb/qtr)** | **PE1 (lb/qtr)** | **QNEC (lb/qtr)** |
| $NO_X$ | 991.25 | 0 | 991.25 |
| $SO_X$ | 244.75 | 0 | 244.75 |
| $PM_{10}$ | 489.50 | 0 | 489.50 |
| CO | 12,443.75 | 0 | 12,443.75 |
| VOC | 698.25 | 0 | 698.25 |

April 13, 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

**RE: Notice of Final Action - Authority to Construct for Lone Oak Energy LLC**
**Facility Number: C-9133**
**Project Number: C-1193519**

Dear Mr. Bryant:

The Air Pollution Control Officer has issued the Authority to Construct permit to Lone Oak Energy LLC for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford. Enclosed are the Authority to Construct permit and a copy of the notice of final action that has been posted on the District's website (www.valleyair.org).

Notice of the District's preliminary decision to issue the Authority to Construct permit was posted on February 21, 2020. The District's analysis of the proposal was also sent to CARB on February 21, 2020. No comments were received following the District's preliminary decision on this project.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Errol Villegas at (559) 230-6000.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

Facility # C-9133
LONE OAK ENERGY LLC
2911 HANFORD ARMONA RD
HANFORD, CA 93230

# AUTHORITY TO CONSTRUCT (ATC)

## *QUICK START GUIDE*

1. **Pay Invoice**: Please pay enclosed invoice before due date.

2. **Fully Understand ATC**: Make sure you understand ALL conditions in the ATC prior to construction, modification and/or operation.

3. **Follow ATC**: You must construct, modify and/or operate your equipment as specified on the ATC. Any unspecified changes may require a new ATC.

4. **Notify District**: You must notify the District's Compliance Department, at the telephone numbers below, upon start-up and/or operation under the ATC. Please record the date construction or modification commenced and the date the equipment began operation under the ATC. You may NOT operate your equipment until you have notified the District's Compliance Department. A startup inspection may be required prior to receiving your Permit to Operate.

5. **Source Test**: Schedule and perform any required source testing. See http://www.valleyair.org/busind/comply/source_testing.htm for source testing resources.

6. **Maintain Records**: Maintain all records required by ATC. Records are reviewed during every inspection (or upon request) and must be retained for at least 5 years. Sample record keeping forms can be found at http://www.valleyair.org/busind/comply/compliance_forms.htm.

By operating in compliance, you are doing your part to improve air quality for all Valley residents.

**For assistance, please contact District Compliance staff at any of the telephone numbers listed below.**


**Samir Sheikh**
Executive Director/Air Pollution Control Officer

**Northern Region**
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

**Central Region (Main Office)**
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

**Southern Region**
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: (661) 392-5500 FAX: (661) 392-5585

www.valleyair.org www.healthyairliving.com

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** C-9133-3-0 **ISSUANCE DATE:** 04/03/2020

**LEGAL OWNER OR OPERATOR:** LONE OAK ENERGY LLC
**MAILING ADDRESS:** 2911 HANFORD ARMONA RD
HANFORD, CA 93230

**LOCATION:** 10014 S MCMULLIN GRDE
FRESNO, CA 93706

**EQUIPMENT DESCRIPTION:**
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

# CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as $H_2S$. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]

11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]

20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]

22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% $O_2$), NOx referenced as $NO_2$; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% $O_2$); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% $O_2$), VOC referenced as $CH_4$. [District Rules 2201 and 4702]

23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]

24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]

25. Ammonia ($NH_3$) emissions from this engine shall not exceed 10 ppmvd @ 15% $O_2$. [District Rules 2201 and 4102]

CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

# ATTACHMENT N

MAR 2 2 2016

N. Ross Buckenham
ABEC #3 LLC dba Lakeview Dairy Biogas
c/o California Bioenergy, LLC
2828 Routh St, Suite 500
Dallas, TX 75201-1438

**Re: Notice of Preliminary Decision - Authority to Construct**
**Facility Number: S-8637**
**Project Number: S-1143770**

Dear Mr. Buckenham:

Enclosed for your review and comment is the District's analysis of ABEC #3 LLC dba Lakeview Dairy Biogas's application for an Authority to Construct for installation of an anaerobic digester system and two 1,468 bhp digester gas-fired IC engines with selective catalytic reduction (SCR) systems for emissions control at Lakeview Farms dairy, at 17702 Bear Mountain Blvd, Bakersfield, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Ramon Norman of Permit Services at (559) 230-5909.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

# San Joaquin Valley Air Pollution Control District

## Authority to Construct Application Review

### Digester System and Two Digester Gas-Fired IC Engines with SCR

| | | | |
|---|---|---|---|
| Facility Name: | ABEC #3 LLC dba Lakeview Dairy Biogas | Date: | March 7, 2016 |
| Mailing Address: | ABEC #3 LLC<br>c/o California Bioenergy, LLC<br>2828 Routh Street, Suite 500<br>Dallas, TX 75201-1438 | Engineer:<br><br>Lead Engineer: | Ramon Norman<br><br>Jerry Sandhu |
| Contact Person: | N. Ross Buckenham - California Bioenergy/ ABEC #3 LLC | | |
| Telephone: | (214) 849-9886 | Cell Phone: | (214) 906-9359 |
| E-Mail: | rbuckenham@calbioenergy.com | | |
| Application #(s): | S-8637-1-0, -2-0, and -3-0 | | |
| Project #: | S-1143770 | | |
| Deemed Complete: | May 14, 2015 | | |

## I. Proposal

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kW. The new digester will be constructed in an area of the existing dairy that is currently used for manure drying and storage. Lakeview Farms dairy will send manure from the dairy to the ABEC #3 LLC anaerobic digesters located on the dairy site. The digester system will produce renewable biogas that will be used to fuel the IC engine generator sets.

ABEC #3 LLC dba Lakeview Dairy Biogas and Lakeview Farms dairy, which are separate companies, are undertaking the project as a partnership. ABEC #3 LLC has provided information supporting that the dairy and the ABEC #3 LLC biogas facility will be separately owned and operated. The following is a summary of some of the information provided by the applicant. The proposed digester system at the dairy will be operated and maintained by ABEC #3 LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with water quality regulations. ABEC #3 LLC will not be involved at all in the dairy's primary activity, production of milk. The feedstock and lease agreements specify that ABEC #3 LLC will build, own, and operate the biogas facility and also allows ABEC #3 LLC to make plant and equipment improvements. The proposed digester gas-fired IC engine generator sets that will be constructed on land leased from the dairy site and will be owned, operated, and maintained by ABEC #3 LLC. ABEC #3 LLC will be solely responsible for ensuring that the digester system and digester gas-fired IC engines comply with all applicable air quality regulations. The generator sets will sell all the power generated to the grid and will not provide any power directly to the dairy. Because the dairy and the proposed digester gas power plant at the site will be separately owned and operated and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the IC engine generator sets), pursuant to Section 3.39 of District Rule 2201, the proposed digester system and the digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, the digester system and digester gas-fired IC engines will be permitted as a separate non-agricultural stationary source (Facility S-8637).

## II. Applicable Rules

| | |
|---|---|
| Rule 2201 | New and Modified Stationary Source Review Rule (4/21/11) |
| Rule 2410 | Prevention of Significant Deterioration (6/16/11) |
| Rule 2520 | Federally Mandated Operating Permits (6/21/01) |
| Rule 4101 | Visible Emissions (2/17/05) |
| Rule 4102 | Nuisance (12/17/92) |
| Rule 4201 | Particulate Matter Concentration (12/17/92) |
| Rule 4701 | Stationary Internal Combustion Engines – Phase 1 (8/21/03) |
| Rule 4702 | Stationary Internal Combustion Engines (11/14/13) |
| Rule 4801 | Sulfur Compounds (12/17/92) |

40 CFR Part 60, Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

40 CFR Part 63, Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

| | |
|---|---|
| CH&SC 41700 | Health Risk Assessment |
| CH&SC 42301.6 | School Notice |

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)

California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

## III. Project Location

The ABEC #3 LLC Stationary Source (Facility S-8637) is located on Lakeview Farms dairy at 17702 Bear Mountain Blvd, Bakersfield, CA (Mt. Diablo Meridian T 31S, R 26E, Sec 20 in Kern County). The proposed equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

## IV. Process Description

### Anaerobic Digester System

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane ($CH_4$), carbon dioxide ($CO_2$), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen ($N_2$), Oxygen ($O_2$), Hydrogen Sulfide ($H_2S$), and Ammonia ($NH_3$). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove $H_2S$ and other impurities and used as fuel.

The proposed anaerobic digester system will be designed to process the manure generated by the cattle at Lakeview Farms dairy. The manure will be flushed from the cow housing areas at the dairy to a mechanical separation system prior to the digester system. This pre-digester mechanical separation system will remove fibrous solids from the manure. After the mechanical separation system, the liquid manure will flow to a sand settling lane that is designed to remove heavy solids by sedimentation. After the separation systems, the liquid manure will gravity flow into the proposed covered lagoon digesters. The liquid effluent from the covered lagoon digesters will be pumped to the existing large storage pond at the dairy from where it can be used to irrigate and fertilize adjacent cropland.

The proposed anaerobic digester system will process the liquid fraction from the dairy manure solid separation system. The anaerobic digester system will consist of an in-ground, covered lagoon anaerobic digester that will be divided into one or more cells. The final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based on borings to locate subsurface sand and groundwater that are required to demonstrate compliance with the requirements of the Regional Water Quality Control Board. The preliminary information submitted by the applicant indicates that the first cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 655 ft long by 262 ft wide at the top, with an average depth of 23 ft, and a side slope (run/rise) of 2.0 and that the second cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 500 ft long by 200 ft wide at the top, with an average depth of 22.75 ft, and a side slope (run/rise) of 2.0. The covered lagoon digester will operate at ambient temperatures; however, the covered lagoon digester may utilize heat from the engines to warm the substrate to promote more efficient anaerobic digestion. An area located east of the existing lagoons at the dairy, which is currently used for drying and storage of solid manure, will be excavated to create the proposed covered lagoon anaerobic digester.

The applicant indicates that the lagoon cell(s) will be covered in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 – Roofs and Covers. The bottom and the walls of the new lagoon cell(s) will be lined with high-density polyethylene (HDPE) membranes and a gas collection system will be installed. The new lagoon cells will be fitted with HDPE covers. The gas collection system will consist of perforated piping under the HDPE covers of the covered lagoons.

The covered lagoon digester will be equipped with an air injection system for removal of $H_2S$ from the digester gas. The continuous injection of controlled quantities of air under the digester covers increases the amount of oxygen in the space under the digester covers and in the surface layer of the digester liquid, which facilitates oxidation of sulfides in the digester gas and at the surface of the liquid to elemental sulfur and water. Injection of air also promotes biological removal of $H_2S$ from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize $H_2S$ to elemental sulfur. The digester gas will be captured by the covered lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional $H_2S$ and for removal of moisture. The gas will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system. When the gas cannot be used in the engines, the digester gas will collect under the lagoon covers. As the gas collects under the lagoon covers, the pressure in the digesters will rise. In rare emergency situations when the gas cannot be combusted in the engines for an extended period, the pressure will cause the relief valves to open and release the digester gas, composed primarily of methane and carbon dioxide, into the atmosphere. As the pressure decreases, the gas relief valves will automatically close and normal operation will proceed.

When operating at full capacity, the digester system is expected to produce an average of 360,000 $ft^3$ of biogas per day. The applicant has indicated that the biogas produced by the covered lagoon digester will be composed of approximately 60-70% methane and 30-40% carbon dioxide. Because the proposed digester system will be able to store the biogas for extended periods under the digester covers and the proposed engines at the ABEC #3 LLC Stationary Source (Facility S-8637) will have more than sufficient capacity to combust all of the gas generated, no flare is being proposed for the digester installation at this facility.

Covered Lagoon Anaerobic Digester Measurements

The measurements given below for the proposed covered lagoon anaerobic digester cells at the ABEC #3 LLC Stationary Source (Facility S-8637) are based on the preliminary information provided by the applicant. As discussed above, the final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based compliance with the requirements of the Regional Water Quality Control Board.

- 1st Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 655 ft long x 262 ft wide
  - Average Depth: 23 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 2,705,808 $ft^3$ (~20,239,444 gal)
- 2nd Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 500 ft long x 200 ft wide
  - Average Depth: 22.75 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 1,613,210 $ft^3$ (~10,612,380 gal)

Digester Gas-Fired IC Engines

The applicant is proposing to install two 1,468 bhp GE Jenbacher model J 320 GS-C82 lean burn digester gas-fired IC engines (or equivalent engines of equal or lesser rating approved by the District, such as 1,412 bhp Caterpillar model A3516A+ IC engines or 1,431 bhp Dresser Rand Guascor model SFGLD 560 IC engines). Each engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,059 kWe. Digester gas, which consists mostly of methane, the main component of natural gas, will be combusted in the IC engines to produce power. After initial removal of $H_2S$ in the digester system, the digester gas will be piped to the gas conditioning system for polishing to remove $H_2S$ using an iron sponge and/or activated carbon $H_2S$ scrubber or an equivalent $H_2S$ removal system and for removal of moisture. The digester gas will then be piped to the IC engines for use as fuel. The engines will power electrical generators that will produce power to be sold to a utility. Excess heat from the engines will be used in the first covered lagoon anaerobic digester (West

Lagoon Digester) to promote more efficient production of digester gas. The engines will be permitted to operate up to 24 hr/day and 8,760 hr/year.

In addition to the use of digester gas as fuel, the engines will also be permitted to use natural gas as fuel for no more than 96,000 kW-hrs of operation during initial utility interconnect testing in the event that insufficient digester gas is available for the engines at the time that the required utility testing is scheduled. The engines will remain subject to the same emission limits during the limited period that allows the use of natural gas fuel for required utility testing.

## V. Equipment Listing

S-8637-1-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

S-8637-2-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

S-8637-3-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

## VI. Emission Control Technology Evaluation

Digester System (S-8637-1-0)

The digester system will be equipped with a pressure-vacuum (PV) relief valves or an emergency venting system. The digester gas will be scrubbed to remove hydrogen sulfide ($H_2S$) and will be used to fuel engines to generate electricity. Combustion of the digester gas in the engines will convert any VOCs present in the gas into carbon dioxide and water. As stated above, because the digester system will be able to store the gas for extended periods and the engines will have more than enough capacity to combust all of the gas generated, no flare is being proposed for this digester project.

$H_2S$ Removal

As described above, the covered lagoon anaerobic digester will utilize an air injection system for removal of $H_2S$ from the digester gas. The continuous injection of controlled quantities of air under the lagoon covers increases the amount of oxygen in the space under the digester covers and the surface layer of the liquid in the covered lagoon digester, which facilitates oxidation of sulfides in the digester gas and in the liquid surface to elemental sulfur and water.

The sulfur dissolves in the liquid in the digester and can be removed from the digester system by deposition and filtration. Injection of air also promotes biological removal of $H_2S$ from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize $H_2S$ to elemental sulfur and sulfates that can be removed from the digester system. Use of air injection to remove $H_2S$ from digester gas has been shown to have higher effectiveness in covered lagoon digesters because the large areas under the lagoon covers facilitate contact with the digester gas and lagoon surface, which enables improved oxidation and biological reduction of sulfides. Successful installations of the air injection sulfur removal system have demonstrated significantly reduced operation costs when compared to other methods of sulfur removal.

For final polishing, the digester gas will be sent through an iron sponge $H_2S$ scrubber and/or an activated carbon $H_2S$ scrubber or an equivalent system to remove $H_2S$ from the gas prior to combustion in the proposed engines.

An iron sponge scrubber is comprised of vessel(s) containing iron sponge, which consists of a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. Iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the $H_2S$ is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \longrightarrow FeS + 2H_2O + \text{heat}$$

For the iron sponge to perform effectively, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas. If the iron sponge becomes dry, it can be re-wet and remain effective. The iron sponge reaction is not pressure sensitive.

Specially treated activated carbon can also be used to remove $H_2S$ from gas streams. $H_2S$ will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a large number of pores, which greatly increase the surface area for adsorption. Contaminants in the gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of $H_2S$ is usually treated with chemical bases to increase the holding capacity for $H_2S$.

The proposed scrubber will consist of enclosed vessels filled with iron sponge and/or treated activated carbon. The digester gas will flow through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge and activated carbon vessels will vary depending on the inlet concentration of $H_2S$, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. Spent iron sponge or activated carbon vessels will be sent to a regeneration facility or to an appropriate disposal facility.

The proposed scrubber will be capable of reducing $H_2S$ concentrations in the digester gas to 40 ppmv or less. Reducing the $H_2S$ concentration in the gas will minimize $SO_X$ emissions from combustion and will also reduce the maintenance requirements for the engines and will protect catalysts from masking, plugging, and poisoning.

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

The proposed engines will be equipped with:
- Turbocharger
- Aftercooler
- Air/Fuel Ratio or an $O_2$ Controller
- Lean Burn Technology
- Positive Crankcase Ventilation (PCV) or 90% efficient control device
- Selective Catalytic Reduction (SCR)

The turbocharger reduces $NO_X$ emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

The aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal $NO_X$.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces $NO_X$ formation.

The PCV system or 90% efficient control device reduces crankcase VOC and $PM_{10}$ emissions by at least 90% over an uncontrolled crankcase vent.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce $NO_X$, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the $NO_X$ emissions by up to 90%.

## VII. General Calculations

### A. Assumptions

- ABEC #3 LLC dba Lakeview Dairy Biogas (Facility S-8637) and Lakeview Farms dairy (Facility S-5254) are separate stationary sources at the same site.
- Because of the high moisture content of separated manure solids, PM emissions from the handling of separated solids for the digester system are considered negligible.
- Because the manure for the digester system will be taken from the mechanical separation system at Lakeview Farms dairy and the digested solids and effluent from the digester system will be returned to Lakeview Farms dairy for use, all emissions from the manure

processed in the digester system will be allocated to the liquid manure handling system at Lakeview Farms dairy.

- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at Lakeview Farms dairy. Manure that is currently stored in uncovered lagoon(s) and pond(s) will instead be placed in covered ponds at the ABEC #3 LLC facility, thereby decreasing volatilization of compounds from the manure. In a digester, most VOCs present will be converted to methane (an exempt compound) and carbon dioxide further reducing the potential for VOC emissions. Because results of dairy digester analyses have indicated very low VOC content (less than 1% by weight), fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015. During operation, the digester gas will be directed to the engines where the gas will be combusted resulting in the oxidation of gaseous hydrocarbons into carbon dioxide and water. Therefore, VOC emissions from the digester system are considered negligible.
- Molar composition of typical digester gas is about 60% methane and 40% carbon dioxide with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]
- Typical Higher Heating Value for Digester Gas: 600 Btu/scf (Per AP-42 (4/00) - notes to Tables Table 3.1-1, Table 3.1-2b, Table 3.1-7, and Table 3.1-8)
- Typical EPA F-factor for Digester Gas: 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
- Average sulfur content of the scrubbed digester gas: 40 ppmv as $H_2S$ (required as BACT; approximately 2.4 grains/100 scf)
- bhp to Btu/hr conversion: 2,545 Btu/hp-hr
- Thermal efficiency of engines: commonly ≈ 33%
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  - $NO_X$ (as $NO_2$) = 46 lb/lb-mol　　CO = 28 lb/lb-mol　　NH3 = 17 lb/lb-mol
  - VOC (as $CH_4$) = 16 lb/lb-mol　　$SO_X$ (as $SO_2$) = 64.06 lb/lb-mol
- Each of the engines will be permitted to operate 24 hours/day and 365 days per year.
- There will be no increase in permitted emissions for the limited use of natural gas for required initial utility testing in the event that sufficient digester gas is not available for the engines at the time that the required initial utility testing is scheduled.
- PM2.5 emissions from the digester gas-fired IC engines are assumed to be equal to PM10 emissions.

[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); American Biogas Council – Frequent Questions (https://www.americanbiogascouncil.org/biogas_questions.asp); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering (http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to Consider", ATTRA - National Sustainable Agriculture Information Service (https://attra.ncat.org/attra-pub/summaries/summary.php?pub=307)

Assumptions for Commissioning Period

- The applicant has requested that the ATC permits include a commissioning period to allow testing, adjustment, tuning, and calibration of the engines without the SCR systems installed. The duration of the commissioning period shall consist of no more than 120 hours of operation of each engine without an SCR system installed.
- Engine emissions during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier.

## B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent damage to this equipment. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[2] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

The emission factors for $NO_X$ (1.0 g/bhp-hr), CO (4.85 g/bhp-hr), and VOC (1.0 g/bhp-hr) for the commissioning period are the emission factors provided by the engine supplier for the engines without SCR systems or oxidation catalysts. The emission factors during the commissioning period for $SO_X$ (0.04 g/bhp-hr), $PM_{10}$ (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) after initial installation of the SCR system are assumed to be the same emissions factors as during normal operation. $SO_X$ emissions are based on the maximum sulfur content of the dairy digester gas (required as BACT; approximately 2.4 grains/100 scf). $PM_{10}$ emissions on a lb/MMBtu basis are assumed to be similar to natural gas-fueled IC engines. For more conservative $PM_{10}$ emission calculations, the PM emission factor for rich burn natural gas-fueled engines given in EPA's Compilation of Air Pollutant Emission Factors (AP-42) is used because it is higher than the value for lean burn natural gas-fueled engines listed in EPA AP-42. The ammonia emission factor is based on the ammonia slip limit of 10 ppmv $NH_3$.

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[2] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/airtoxics/icengines/docs/20120717riceqaupdate.pdf)

| Commissioning Period Emission Factors for Digester Gas-Fired Engines | | |
|---|---|---|
| Pollutant | g/bhp·hr | Source |
| $NO_X$ | 1.0 | Engine Supplier's Information |
| $SO_X$ | 0.04 | 40 ppmvd in fuel gas; BACT Requirement/Mass Balance equation below |
| $PM_{10}$ | 0.07 | AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines) |
| CO | 4.85 | Engine Supplier's Information |
| VOC | 1.0 | Engine Supplier's Information |
| $NH_3$ | 0.05 | 10 ppmvd @ 15% $O_2$ in exhaust; Required/Proposed – See equation below |

$SO_X$ – 40 ppmvd $H_2S$ in fuel gas

$$\frac{40\,\text{ft}^3\ \text{H}_2\text{S}}{10^6\ \text{ft}^3} \times \frac{32.06\ \text{lb S}}{\text{lb - mol H}_2\text{S}} \times \frac{\text{lb - mole}}{379.5\ \text{ft}^3} \times \frac{64.06\ \text{lb SO}_2}{32.06\ \text{lb S}} \times \frac{\text{ft}^3}{600\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.0113\ \frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.0113\ \frac{\text{lb SOx}}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{\text{Btu}_{in}}{0.33\text{Btu}_{out}} \times \frac{2{,}545\ \text{Btu}}{\text{hp - hr}} \times \frac{453.59\ \text{g}}{\text{lb}} = 0.040\ \frac{\text{g SOx}}{\text{bhp - hr}}$$

$NH_3$ – 10 ppmvd @ 15% $O_2$ in exhaust

$$\frac{10\ \text{ppmv NH}_3}{10^6} \times \frac{17\ \text{lb NH}_3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{379.5\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{\text{MMBtu}} \times \frac{20.9\%\ \text{O}_2}{(20.9 - 15)\%\ \text{O}_2} = 0.0144\ \frac{\text{lb NH}_3}{\text{MMBtu}}$$

$$0.0144\ \frac{\text{lb NH}_3}{\text{MMBtu}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \times \frac{\text{Btu}_{in}}{0.33\text{Btu}_{out}} \times \frac{2{,}545\ \text{Btu}}{\text{hp - hr}} \times \frac{453.59\ \text{g}}{\text{lb}} = 0.05\ \frac{\text{g NH}_3}{\text{bhp - hr}}$$

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for $NO_X$ (0.15 g/bhp-hr), CO (1.75 g/bhp-hr), and VOC (0.10 g/bhp-hr) for the proposed engines during normal operation were proposed by the applicant and are supported by information provided by the engine supplier. The emission factors for $NO_X$ and VOC were required as BACT. The emission factors for $SO_X$ (0.04 g/bhp-hr), $PM_{10}$ (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) during normal operation are same as the emission factors presented above for the commissioning period.

| Emission Factors for Digester Gas-Fired Engines (Normal Operation) | | | | |
|---|---|---|---|---|
| Pollutant | g/bhp·hr | lb/MMBtu | ppmvd (@ 15%$O_2$) | Source |
| $NO_X$ | 0.15 | 0.0429 | 11 ppmvd | BACT Requirement; Proposed by Applicant – See equation on Page 11 below |
| $SO_X$ | 0.04 | 0.0113 | 40 ppmvd in fuel gas | BACT Requirement/Mass Balance equation above |
| $PM_{10}$ | 0.07 | 0.01941 | -- | AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines) |
| CO | 1.75 | 0.500 | 210 ppmvd | Proposed by Applicant – See equation on Page 11 below |
| VOC | 0.10 | 0.0286 | 21 ppmvd as $CH_4$ | BACT Requirement; Proposed by Applicant – See equation on Page 11 below |
| $NH_3$ | 0.05 | 0.0144 | 10 ppmvd | Required/Proposed – See equation above |

$NO_X$ – 0.15 g/bhp-hr

$$0.15\,\frac{\text{g NOx}}{\text{bhp - hr}}\times\frac{1\,\text{lb}}{453.59\,\text{g}}\times\frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}}\times\frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}}\times\frac{10^6\,\text{Btu}}{1\,\text{MMBtu}}=0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}}\times\frac{(20.9-15)\%\ O_2}{20.9\%\ O_2}\times\frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3}\times\frac{379.5\,\text{ft}^3}{\text{lb - mole}}\times\frac{\text{lb - mole}}{46\,\text{lb NOx}}\times\frac{10^6\,\text{ppmv}}{1}=11\ \text{ppmvd NOx @ 15\% } O_2$$

CO – 1.75 g/bhp-hr

$$1.75\,\frac{\text{g CO}}{\text{bhp - hr}}\times\frac{1\,\text{lb}}{453.59\,\text{g}}\times\frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}}\times\frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}}\times\frac{10^6\,\text{Btu}}{1\,\text{MMBtu}}=0.500\,\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.500\,\frac{\text{lb CO}}{\text{MMBtu}}\times\frac{(20.9-15)\%\ O_2}{20.9\%\ O_2}\times\frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3}\times\frac{379.5\,\text{ft}^3}{\text{lb - mole}}\times\frac{\text{lb - mole}}{28\,\text{lb CO}}\times\frac{10^6\,\text{ppmv}}{1}=210\ \text{ppmvd CO @ 15\% } O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\,\frac{\text{g VOC}}{\text{bhp - hr}}\times\frac{1\,\text{lb}}{453.59\,\text{g}}\times\frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}}\times\frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}}\times\frac{10^6\,\text{Btu}}{1\,\text{MMBtu}}=0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}}\times\frac{(20.9-15)\%\ O_2}{20.9\%\ O_2}\times\frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3}\times\frac{379.5\,\text{ft}^3}{\text{lb - mole}}\times\frac{\text{lb - mole}}{16\,\text{lb VOC}}\times\frac{10^6\,\text{ppmv}}{1}=21\ \text{ppmvd VOC @ 15\% } O_2$$

## C. Calculations

### 1. Pre-Project Potential to Emit (PE1)

Since the digester system and the engines are new emissions units, PE1 = 0 for all affected pollutants.

### 2. Post Project Potential to Emit (PE2)

Digester System (S-8637-1-0)

As explained above, the digester system will be composed of sealed lagoons that will reduce VOC emissions from the manure and will have negligible fugitive emissions; therefore, VOC emissions from the manure will only be attributed to Lakeview Farms dairy for manure prior to entering the digester system and when returned to the dairy and emissions from the digester system are considered negligible.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

Daily PE2 for Each Engine during the Commissioning Period:

Daily PE during the commissioning period for each of the proposed engines is calculated in the table below:

| Daily PE for Engines S-8637-2-0 &-3-0 During the Commissioning Periods | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 1.0 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **77.7** | (lb/day) |
| $SO_X$ | 0.04 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **3.1** | (lb/day) |
| $PM_{10}$ | 0.07 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **5.4** | (lb/day) |
| CO | 4.85 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **376.7** | (lb/day) |
| VOC | 1.0 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **77.7** | (lb/day) |
| $NH_3$ | 0.05 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **3.9** | (lb/day) |

Daily PE2 for Each Engine during Normal Operation after the Commissioning Period:

Daily PE for each of the proposed engines during normal operation after completion of the commissioning periods is calculated in the table below:

| Daily PE for Engines S-8637-2-0 &-3-0 After Commissioning | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 0.15 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **11.7** | (lb/day) |
| $SO_X$ | 0.04 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **3.1** | (lb/day) |
| $PM_{10}$ | 0.07 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **5.4** | (lb/day) |
| CO | 1.75 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **135.9** | (lb/day) |
| VOC | 0.10 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **7.8** | (lb/day) |
| $NH_3$ | 0.05 | (g/hp·hr) x | 1,468 | (hp) x | 24 | (hr/day) ÷ 453.59 (g/lb) = | **3.9** | (lb/day) |

Maximum Annual PE2 for Each Engine During the first Year Including the Commissioning Periods:

As discussed above, each of the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

$NO_X$

1,468 bhp x (1.0 g-$NO_X$/bhp-hr x 120 hr + 0.15 g-$NO_X$/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **4,583 lb-$NO_X$**

$SO_X$

1,468 bhp x (0.04 g-$SO_X$/bhp-hr x 120 hr + 0.04 g-$SO_X$/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,134 lb-$SO_X$**

$PM_{10}$

1,468 bhp x (0.07 g-$PM_{10}$/bhp-hr x 120 hr + 0.07 g-$PM_{10}$/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,985 lb-$PM_{10}$**

CO

1,468 bhp x (4.85 g-CO/bhp-hr x 120 hr + 1.75 g-CO/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **50,818 lb-CO**

VOC
1,468 bhp x (1.0 g-VOC/bhp-hr x 120 hr + 0.10 g-VOC/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **3,185 lb-VOC**

$NH_3$
1,468 bhp x (0.05 g-$NH_3$/bhp-hr x 120 hr + 0.05 g-$NH_3$/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **1,418 lb-$NH_3$**

Maximum Total Combined Annual PE2 from Both Engines, Including Commissioning:

The maximum total combined annual PE2 for both the engines, including commissioning emissions, is calculated as follows:

$NO_X$: 4,583 lb-$NO_X$/yr-engine x 2 engines = **9,166 lb-$NO_X$/yr**
$SO_X$: 1,134 lb-$SO_X$/yr-engine x 2 engines = **2,268 lb-$SO_X$/yr**
$PM_{10}$: 1,985 lb-$PM_{10}$/yr-engine x 2 engines = **3,970 lb-$PM_{10}$/yr**
CO: 50,818 lb-CO/yr-engine x 2 engines = **101,636 lb-CO/yr**
VOC: 3,185 lb-VOC/yr-engine x 2 engines = **6,370 lb-VOC/yr**
$NH_3$: 1,418 lb-$NH_3$/yr-engine x 2 engines = **2,836 lb-$NH_3$/yr**

Annual PE2 for Each Engine in years with no Commissioning:

The annual PE2 for each of the engines after completion of the first year of operation when there will not be any commissioning emissions is calculated as follows:

| **Annual PE2 for Engines S-8637-2-0 &-3-0 with no Commissioning** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| $NO_X$ | 0.15 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **4,253** | (lb/yr) |
| $SO_X$ | 0.04 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **1,134** | (lb/yr) |
| $PM_{10}$ | 0.07 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **1,985** | (lb/yr) |
| CO | 1.75 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **49,614** | (lb/yr) |
| VOC | 0.10 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **2,835** | (lb/yr) |
| $NH_3$ | 0.05 | (g/hp·hr) x | 1,468 | (hp) x | 8,760 | (hr) ÷ 453.59 (g/lb) = | **1,418** | (lb/yr) |

Max Total Combined Annual PE2 from Both Engines in years with no Commissioning:

The maximum total combined annual PE2 for both the engines in years with no commissioning is calculated as follows:

$NO_X$: 4,253 lb-$NO_X$/yr-engine x 2 engines = **8,506 lb-$NO_X$/yr**
$SO_X$: 1,134 lb-$SO_X$/yr-engine x 2 engines = **2,268 lb-$SO_X$/yr**
$PM_{10}$: 1,985 lb-$PM_{10}$/yr-engine x 2 engines = **3,970 lb-$PM_{10}$/yr**
CO: 49,614 lb-CO/yr-engine x 2 engines = **99,228 lb-CO/yr**
VOC: 2,835 lb-VOC/yr-engine x 2 engines = **5,670 lb-VOC/yr**
$NH_3$: 1,418 lb-$NH_3$/yr-engine x 2 engines = **2,836 lb-$NH_3$/yr**

**Maximum Daily and Annual PE2 from Calculations Above:**

The maximum daily and annual emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

| Max. Post-Project Potential to Emit (PE2) for S-8637-2-0 &-3-0 | | | |
|---|---|---|---|
| | Max. Daily Emissions for each engine (lb/day) | Max. Annual Emissions for each engine (lb/year) | Max. Total Combined Annual Emissions for both engines (lb/year) |
| $NO_X$ | 77.7 | 4,583 | 9,166 |
| $SO_X$ | 3.1 | 1,134 | 2,268 |
| $PM_{10}$ | 5.4 | 1,985 | 3,970 |
| CO | 376.7 | 50,818 | 101,636 |
| VOC | 77.7 | 3,185 | 6,370 |
| $NH_3$ | 3.9 | 1,418 | 2,836 |

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

### 4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

| SSPE2 (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| Permit Unit | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC | $NH_3$ |
| ATC S-8637-1-0 (Digester System) | 0 | 0 | 0 | 0 | 0 | 0 |
| ATC S-8637-2-0 (1,468 bhp Digester Gas Engine)[3] | 4,583 | 1,134 | 1,985 | 50,818 | 3,185 | 1,418 |
| ATC S-8637-3-0 (1,468 bhp Digester Gas Engine)[3] | 4,583 | 1,134 | 1,985 | 50,818 | 3,185 | 1,418 |
| SSPE2 | 9,166 | 2,268 | 3,970 | 101,636 | 6,370 | 2,836 |

[3] The SSPE2 values listed in this table include the worst case annual emissions during the 120 hours of allowed commissioning time where the engines are allowed to operate uncontrolled for setup and tuning purposes. After the first year, the PE for $NO_X$, CO, and VOC emissions will go down as the engines will no longer be allowed to operate without controls in place for these pollutants.

## 5. Major Source Determination

**Rule 2201 Major Source Determination:**

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. transportable IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

| **Rule 2201 Major Source Determination (lb/year)** | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | $SO_X$ | $PM_{10}$ | $PM_{2.5}$ | CO | VOC |
| SSPE1 | 0 | 0 | 0 | 0 | 0 | 0 |
| SSPE2 | 9,166 | 2,268 | 3,970 | 3,970 | 101,636 | 6,370 |
| Major Source Threshold | 20,000 | 140,000 | 140,000 | 200,000* | 200,000 | 20,000 |
| Major Source? | No | No | No | No | No | No |

* The application for this project was deemed complete before 2/18/2016, which was when the District's PM2.5 Major Source Threshold was lowered to 140,000 lb/year

Note: PM2.5 assumed to be equal to PM10

**Rule 2410 Major Source Determination:**

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

| **PSD Major Source Determination (tons/year)** | | | | | | |
|---|---|---|---|---|---|---|
| | NO2 | VOC | SO2 | CO | PM | PM10 |
| Estimated Facility PE before Project Increase | 0 | 0 | 0 | 0 | 0 | 0 |
| PSD Major Source Thresholds | 250 | 250 | 250 | 250 | 250 | 250 |
| PSD Major Source ? (Y/N) | N | N | N | N | N | N |

Because this is a new facility, the PE for all regulated NSR pollutants prior to the project is equal to zero.

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

**6. Baseline Emissions (BE)**

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the proposed digester system and engines are new emissions units, BE = PE1 = 0 for all pollutants from each unit.

**7. SB 288 Major Modification**

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

**8. Federal Major Modification**

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for $PM_{10}$ (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year since the application for the project was deemed complete before 2/18/2016).

**9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination**

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)[4]
- Total reduced sulfur (inlcuding H2S)[4]

### I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

| PSD Major Source Determination: Potential to Emit (tons/year) | | | | | | |
|---|---|---|---|---|---|---|
| | NO2 | VOC | SO2 | CO | PM | PM10 |
| Total PE from New and Modified Units | 4.6 | 3.2 | 1.1 | 50.8 | 2.0 | 2.0 |
| PSD Major Source threshold | 250 | 250 | 250 | 250 | 250 | 250 |
| New PSD Major Source? | N | N | N | N | N | N |

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

### 10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix A.

[4] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily $H_2S$) in the fuel will be converted almost entirely to $SO_X$ during combustion, the maximum possible amount of $H_2S$ and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as $H_2S$. Based on the fuel sulfur limit of 40 ppmv as $H_2S$, the maximum possible $H_2S$ emission factor for the engines is calculated to be 0.02 g-$H_2S$/bhp (0.0056 lb-$H_2S$/MMBtu), resulting in a total combined maximum of < 0.06 tpy $H_2S$ from the exhaust stacks of both engines. This is well below the applicable PSD threshold of 250 tpy.

# VIII. Compliance

## Rule 2201 New and Modified Stationary Source Review Rule

### A. Best Available Control Technology (BACT)

#### 1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

**a. New emissions units – PE > 2 lb/day**

As seen in Section VII.C.2 above, the applicant is proposing to install a new digester system with and two new digester gas-fired IC engines.

<u>Digester System (S-8637-1-0)</u>

As explained above, the digester system will consist of sealed lagoon(s) that will reduce VOC emissions from the manure at the dairy and emissions from the digester system are considered negligible. Therefore BACT for new units with PE > 2 lb/day purposes is not required for the digester system.

<u>Digester Gas-Fired Engines (S-8637-2-0 and -3-0)</u>

The proposed engines will each have a PE greater than 2.0 lb/day for $NO_X$, $SO_X$, $PM_{10}$, CO, VOC, and $NH_3$. Therefore, BACT is triggered for $NO_X$, $SO_X$, $PM_{10}$, and VOC. As part of the BACT requirements, $NH_3$ slip from the SCR systems will also be limited. The PE for CO from each unit also exceeds 2.0 lb/day; however, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

**b. Relocation of emissions units – PE > 2 lb/day**

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

**c. Modification of emissions units – AIPE > 2 lb/day**

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

**d. SB 288/Federal Major Modification**

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

**2. BACT Guideline**

S-8637-2-0 & -3-0

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines. (See Appendix B)

**3. Top-Down BACT Analysis**

Pursuant to the Top-Down BACT Analysis (See Appendix B), BACT has been satisfied with the following:

$NO_X$: $NO_X$ emissions ≤ 0.15 g/bhp-hr
$SO_X$: Fuel sulfur content ≤ 40 ppmv (as $H_2S$)
$PM_{10}$: Fuel sulfur content ≤ 40 ppmv (as $H_2S$)
VOC: VOC emissions ≤ 0.10 g/bhp-hr
$NH_3$: $NH_3$ slip emissions ≤ 10 ppmv @ 15% $O_2$

**B. Offsets**

**1. Offset Applicability**

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

| Offset Determination (lb/year) | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | $SO_X$ | $PM_{10}$ | CO | VOC |
| SSPE2 | 9,166 | 2,268 | 3,970 | 101,636 | 6,370 |
| Offset Thresholds | 20,000 | 54,750 | 29,200 | 200,000 | 20,000 |
| Offsets triggered? | No | No | No | No | No |

### 2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

## C. Public Notification

### 1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

#### a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

#### b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

The PE2 for the proposed new IC engines is compared to the daily PE Public Notice thresholds in the following table:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

| **PE > 100 lb/day Public Notice Thresholds** | | | |
|---|---|---|---|
| Pollutant | PE2 (lb/day) | Public Notice Threshold | Public Notice Triggered? |
| $NO_X$ | 77.7 | 100 lb/day | No |
| $SO_X$ | 3.1 | 100 lb/day | No |
| $PM_{10}$ | 5.4 | 100 lb/day | No |
| CO | 376.7 | 100 lb/day | **Yes** |
| VOC | 77.7 | 100 lb/day | No |
| $NH_3$ | 3.9 | 100 lb/day | No |

Therefore, public noticing for PE > 100 lb/day purposes is required.

**c. Offset Threshold**

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

| **Offset Thresholds** | | | | |
|---|---|---|---|---|
| Pollutant | SSPE1 (lb/year) | SSPE2 (lb/year) | Offset Threshold | Public Notice Required? |
| $NO_X$ | 0 | 9,166 | 20,000 lb/year | No |
| $SO_X$ | 0 | 2,268 | 54,750 lb/year | No |
| $PM_{10}$ | 0 | 3,970 | 29,200 lb/year | No |
| CO | 0 | 101,636 | 200,000 lb/year | No |
| VOC | 0 | 6,370 | 20,000 lb/year | No |

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

**d. SSIPE > 20,000 lb/year**

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

| **SSIPE Public Notice Thresholds** | | | | | |
|---|---|---|---|---|---|
| Pollutant | SSPE2 (lb/year) | SSPE1 (lb/year) | SSIPE (lb/year) | SSIPE Public Notice Threshold | Public Notice Required? |
| $NO_x$ | 9,166 | 0 | 9,166 | 20,000 lb/year | No |
| $SO_x$ | 2,268 | 0 | 2,268 | 20,000 lb/year | No |
| $PM_{10}$ | 3,970 | 0 | 3,970 | 20,000 lb/year | No |
| CO | 101,636 | 0 | 101,636 | 20,000 lb/year | **Yes** |
| VOC | 6,370 | 0 | 6,370 | 20,000 lb/year | No |
| $NH_3$ | 2,836 | 0 | 2,836 | 20,000 lb/year | No |

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE > 20,000 lbs is required.

**e. Title V Significant Permit Modification**

Since this facility does not have a Title V operating, this change is not a Title V Significant Modification, and therefore public noticing is not required.

**2. Public Notice Action**

As discussed above, public noticing is required for this project for CO emissions from an emissions unit in excess of 100 lb/day and for an SSIPE for CO that exceeds 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

**D. Daily Emission Limits (DELs)**

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and must be enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

***Proposed Rule 2201 (DEL) Conditions for the Digester System (S-8637-1-0)***

As stated above, the digester system will reduce emissions from the manure produced by cattle at Lakeview Farms dairy. The following condition will be placed on the ATC permit to ensure that fugitive emissions from the digester system will be negligible:

- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]

***Proposed Rule 2201 (DEL) Conditions for the Digester Gas-Fired Engines (S-8637-2-0 & -3-0)***

Proposed Rule 2201 (DEL) Conditions for Engines during Both Commissioning and Normal Operation:

- This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

- During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
- The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For these digester gas-fired IC engines, the DELs for $NO_X$, $PM_{10}$, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr) and maximum number of hours allowed for commissioning activities.

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

For the proposed digester gas-fired IC engines, the DELs for $NO_X$, $PM_{10}$, CO, and VOC during normal operation are stated in the form of emission factors (g/hp-hr & ppmv), the maximum engine horsepower rating (1,468 bhp), and the maximum operational time of 24 hours per day.

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

## E. Compliance Assurance

### 1. Source Testing

The proposed 1,468 bhp digester gas-fired engines are subject to District Rule 4702 - Internal Combustion Engines. Section 6.3.2.1 of District Rule 4702 requires source testing of $NO_X$, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The periodic source testing required by District Rule 4702 will ensure compliance with the applicable New Source Review (NSR) requirements $NO_X$, CO, and VOC. Therefore, source testing for $NO_X$, CO, and VOC will be required within 90 days of initial start-up and at least once 24 months thereafter. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The $PM_{10}$ emissions from the engine are not expected to change much over time as long as the quality of the gas used to fuel the engines remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial $PM_{10}$ source testing will be required to demonstrate compliance with the $PM_{10}$ emission limit, but ongoing $PM_{10}$ source testing will not be required.

The proposed engines are also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, no testing requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

The following conditions will be placed on the engine permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided it to the District upon request. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

**2. Monitoring**

As stated above the engines are subject to District Rule 4702. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of $NO_X$ emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. Therefore, quarterly monitoring of $NO_X$, CO, and $O_2$ concentrations in accordance with pre-approved alternate monitoring plan "A" within District Policy SSP 1810 will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the engine permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the engine permits to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

### 3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the engine permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or

volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

#### 4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

As stated above, the proposed 1,468 bhp engines are subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. As explained above, the District has not been delegated the authority to implement this regulation for non-Major Sources; therefore, this requirement will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

### F. Ambient Air Quality Analysis (AAQA)

District Rule 2201 requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for $NO_X$, CO, and $SO_X$. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for $NO_X$, CO, or $SO_X$. The proposed location is in a non-attainment area for the state's $PM_{10}$ as well as federal and state $PM_{2.5}$ thresholds.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table:

| Criteria Pollutant Modeling Results* | | | | | |
|---|---|---|---|---|---|
| Digester Gas-Fired IC Engines | 1 Hour | 3 Hours | 8 Hours. | 24 Hours | Annual |
| CO | Pass | X | Pass | X | X |
| $NO_X$ | Pass[1] | X | X | X | Pass |
| $SO_X$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[2] | Pass[2] |
| H2S | Pass | X | X | X | X |

* Results were taken from the PSD spreadsheet.

[1] The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

[2] The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

[3] $H_2S$ emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

**Rule 2410 Prevention of Significant Deterioration**

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

**Rule 2520 Federally Mandated Operating Permits**

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

**Rule 4101 Visible Emissions**

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

Since the IC engines are fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**Rule 4102 Nuisance**

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

**California Health & Safety Code 41700 (Health Risk Assessment)**

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix C), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project. The results of the health risk assessment are summarized in the table below.

| RMR Summary | | | |
|---|---|---|---|
| Categories | 1,468 bhp Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0) | Project Totals | Facility Totals |
| Prioritization Score[1] | 107 (each) | 214 | >1 |
| Acute Hazard Index | 0.48 (each)[1] | 0.95 | 0.95 |
| Chronic Hazard Index | 0.16 (each) | 0.31 | 0.31 |
| Maximum Individual Cancer Risk ($10^{-6}$) | 0.002 (each) | 0.004 | 0.004 |
| T-BACT Required? | No | | |
| Special Permit Conditions? | Yes | | |

[1] $H_2S$ emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

### Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix C of this report, the emissions increases for this project was determined to be less than significant.

To ensure compliance with the HRA; the following condition will be listed on the engine permits:

<u>Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

This condition, along with the engine rating in the equipment description, will ensure that the $H_2S$ emissions from the engine exhaust stack shall not exceed 1.97 lb/hr, as required by the Health Risk Assessment.

### Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.07 \quad \frac{g}{hp \cdot hr} \times \frac{1 hp \cdot hr}{2{,}545 Btu} \times \frac{10^6 Btu}{9{,}100 dscf} \times \frac{0.33 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = \quad 0.015 \quad \frac{grain}{dscf}$$

Since 0.015 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**Rule 4701 Stationary Internal Combustion Engines – Phase I**

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

**Rule 4702 Internal Combustion Engines**

The purpose of this rule is to limit the emissions of nitrogen oxides ($NO_X$), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides ($SO_X$) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0. The proposed new engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 $NO_X$, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 $SO_X$ control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and

5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the $NO_X$ emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. Pursuant to Section 5.2.2.2.2, compliance with Section 5.7 and 5.10, pursuant to the deadlines specified in Section 7.5, is also required as part of the fee payment option.

Section 5.2.2.3 allows that in lieu of complying with the $NO_X$, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

**Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations**
(Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)

| Engine Type | $NO_X$ Emission Limit (ppmv @ 15% $O_2$, dry) | CO Emission Limit (ppmv @ 15% $O_2$, dry) | VOC Emission Limit (ppmv @ 15% $O_2$, dry) |
|---|---|---|---|
| 1. a. Rich-Burn, Waste Gas Fueled | 50 ppmv | 2,000 ppmv | 250 ppmv |
| 1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled | 50 ppmv | 2,000 ppmv | 250 ppmv |
| 1. c. Rich-Burn, Limited Use | 25 ppmv | 2,000 ppmv | 250 ppmv |
| 1. d. Rich-Burn, Not Listed Above | 11 ppmv | 2,000 ppmv | 250 ppmv |
| 2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp | 75 ppmv | 2,000 ppmv | 750 ppmv |
| 2. b. Lean-Burn, Limited Use | 65 ppmv | 2,000 ppmv | 750 ppmv |
| 2. c. Lean-Burn Engine used for gas compression | 65 ppmv or 93% reduction | 2,000 ppmv | 750 ppmv |
| 2. d. Waste Gas Fueled | 65 ppmv or 90% reduction | 2,000 ppmv | 750 ppmv |
| 2. e. Lean-Burn, Not Listed Above | 11 ppmv | 2,000 ppmv | 750 ppmv |

The proposed digester gas-fired engines will be operated as a separate stationary source than the dairy farm and the District has determined that the IC engines are a non-agricultural IC engines. The digester gas-fired, engines are waste gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.d: 65 ppmvd $NO_X$, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% $O_2$).

Therefore, the following previously presented condition will be listed on the proposed ATC permits for the engines to ensure compliance:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the $NO_X$, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

As stated above, the proposed digester gas-fired engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed digester gas-fired engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the $NO_X$ emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the $NO_X$ emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the digester gas-fired engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore payment of annual emissions fees for the engines is not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or

5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or

5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or

5.7.4 Use California Reformulated Diesel for compression-ignited engines; or

5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or

5.7.6 Install and properly operate an emission control system that reduces $SO_2$ emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be listed on the proposed engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for $NO_X$, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic $NO_X$ and CO emission concentrations,

5.8.1.2 Engine exhaust oxygen concentration,

5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the Rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic $NO_X$, CO, and $O_2$ emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the engine ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic $NO_X$, CO, and $O_2$ emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed ATC permits for the proposed digester gas-fired engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be placed on the engine ATC permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, use of a portable $NO_X$ analyzer to take $NO_X$ emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one $NO_X$ emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All $NO_X$ emissions readings shall be reported to the APCO in a manner approved by the APCO. $NO_X$ emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that requires periodic $NO_X$, CO, and $O_2$ emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer's instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed spark-ignited non-agricultural digester gas-fired engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies $SO_X$ Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed spark-ignited non-agricultural digester gas-fired engines are required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.1.1.2 Engines subject to Section 8.0;
6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for each engine:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of $NO_X$, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the IC engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the ATC permits:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on the proposed ATC permits to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included the ATC permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the

Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, $NO_X$, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of $NO_X$ emissions shall also be reported.

The following conditions will be included in the ATC permits to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled on digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 $SO_X$ Test Methods
6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.

6.4.6.2 Determination of total sulfur as hydrogen sulfide ($H_2S$) content – EPA Method 11 or EPA Method 15, as appropriate.
6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
6.4.6.4 The $SO_X$ emission control system efficiency shall be determined using the following:
% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$
Where:
$C_{SO2,\ inlet}$ = concentration of $SO_X$ (expressed as $SO_2$) at the inlet side of the $SO_X$ emission control system, in lb/Dscf
$C_{SO2,\ outlet}$ = concentration of $SO_X$ (expressed as $SO_2$) at the outlet side of the $SO_X$ emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:
6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.
6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the proposed ATC permits to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:
6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of $NO_X$ and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of $NO_X$ and oxidation catalysts for control of CO and VOC. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule.

$NO_X$ Emissions:

In order to satisfy the I & M requirements for $NO_X$ emissions, the applicant has proposed to perform the following:

1. Measurement of NOx emissions concentrations with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and the catalyst control system inlet exhaust temperature and $NO_X$ emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

CO and VOC Emissions:

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emissions concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure and CO emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance with the I & M requirements for $NO_X$, CO, and VOC:

- Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]
- Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s)

within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust $NO_X$, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust $NO_X$, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control

system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be listed on the proposed ATC permits:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Section 6.5.7 requires procedures and a schedule for using a portable $NO_X$ analyzer to take $NO_X$ emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule. The following previously proposed condition will be listed on the proposed ATC permits:

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time.

The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule. The following condition will be listed on the proposed ATC permits to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed IC engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the $NO_X$ emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate $NO_X$ emission level that is ≤ 90% of the $NO_X$ emissions that would be obtained by controlling the engines to comply individually with the $NO_X$ limits in Section 5.2; the operator shall establish a $NO_X$ emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines proposed under this project; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the IC engines under this project is not currently being proposed and, in addition, certification under this section of the Rule would require that the engines or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore this section of the Rule is not applicable.

Conclusion

As shown above, the proposed non-agricultural, digester gas-fired, lean burn, IC engines are expected to comply with the applicable requirements of Rule 4702 upon initial operation and no further discussion is required.

**Rule 4801 Sulfur Compounds**

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as $SO_2$) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of $SO_X$ as ($SO_2$) = (n x R x T) ÷ P
Where:

n = moles $SO_X$
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$0.0113\ \frac{lb}{MMBtu}\times\frac{1\,MMBtu}{9{,}100\,scf_{exhaust}}\times\frac{1\,lb\cdot mol}{64\,lb\cdot SO_2}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times 1{,}000{,}000\,ppm = 7.4\ \text{ppmv}$$

Since 7.4 ppmv is ≤ 2000 ppmv, the engines are expected to comply with Rule 4801. The following condition will be placed on the engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

**40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines**

This rule incorporates the New Source Performance Standards (NSPS) from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of $NO_X$, $SO_X$, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,468 bhp SI ICEs that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

**40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines**

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part. As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

**California Health & Safety Code 42301.6 (School Notice)**

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Environmental Quality Act (CEQA)**

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

**Greenhouse Gas (GHG) Significance Determination**

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for construction of a renewable energy plant at an existing dairy facility. The proposed renewable energy plant will combust dairy digester gas in IC engines to produce electricity. The proposed project will involve diverting manure from existing open basin(s) and pond(s) at the dairy to covered lagoon digester(s), which will result in the capture of much of the methane that is currently released into the atmosphere from the open basins and pond at the dairy. Combustion of the dairy digester gas at the proposed renewable energy plant will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digesters will result in a large net decrease in the global warming potential emitted from the dairy when compared to current levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

**District CEQA Findings**

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that, although the project is considered to take place at a separate stationary source for NSR purposes, the activity will occur on previously developed land at an existing dairy facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

## IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8637-1-0, -2-0, and -3-0 subject to the permit conditions on the attached draft ATC in Appendix D.

## X. Billing Information

| Annual Permit Fees | | | |
|---|---|---|---|
| Permit Number | Fee Schedule | Fee Description | Annual Fee |
| S-8367-1-0 | 3020-06 | Covered Lagoon Digester | $111.00 |
| S-8367-2-0 | 3020-10-F | 1,468 bhp IC engine | $785.00 |
| S-8367-3-0 | 3020-10-F | 1,468 bhp IC engine | $785.00 |

### Appendixes

A: Quarterly Net Emissions Change (QNEC)
B: BACT Analysis for the Proposed Digester Gas-Fired IC Engines
C: Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)
D: Draft ATCs (S-8367-1-0, -2-0, & -3-0)

# APPENDIX A
## Quarterly Net Emissions Change (QNEC)

**Quarterly Net Emissions Change (QNEC)**

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

S-8637-1-0 (Digester System)

| PE1 (lb/qtr) S-8637-1-0 | | | | | |
|---|---|---|---|---|---|
| | PE1 (lb/year) | ÷ | 4 qtr/year | = | PE1 (lb/qtr) |
| $NO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $SO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $PM_{10}$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| CO | 0 | ÷ | 4 qtr/year | = | 0.0 |
| VOC | 0 | ÷ | 4 qtr/year | = | 0.0 |

| PE2 (lb/qtr) S-8637-1-0 | | | | | |
|---|---|---|---|---|---|
| | PE2 (lb/year) | ÷ | 4 qtr/year | = | PE2 (lb/qtr) |
| $NO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $SO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $PM_{10}$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| CO | 0 | ÷ | 4 qtr/year | = | 0.0 |
| VOC | 0 | ÷ | 4 qtr/year | = | 0.0 |

| Quarterly NEC [QNEC] S-8637-1-0 | | | | | |
|---|---|---|---|---|---|
| | PE2 (lb/qtr) | - | PE1 (lb/qtr) | = | NEC (lb/qtr) |
| $NO_X$ | 0.0 | - | 0.0 | = | 0.0 |
| $SO_X$ | 0.0 | - | 0.0 | = | 0.0 |
| $PM_{10}$ | 0.0 | - | 0.0 | = | 0.0 |
| CO | 0.0 | - | 0.0 | = | 0.0 |
| VOC | 0.0 | - | 0.0 | = | 0.0 |

S-8637-2-0 & -3-0 (1,468 bhp Digester Gas-Fired, Lean Burn, IC Engines)

| PE1 (lb/qtr) S-8637-2-0 & -3-0 | | | | | |
|---|---|---|---|---|---|
| | PE1 (lb/year) | ÷ | 4 qtr/year | = | PE1 (lb/qtr) |
| $NO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $SO_X$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| $PM_{10}$ | 0 | ÷ | 4 qtr/year | = | 0.0 |
| CO | 0 | ÷ | 4 qtr/year | = | 0.0 |
| VOC | 0 | ÷ | 4 qtr/year | = | 0.0 |

| PE2 (lb/qtr) S-8637-2-0 & -3-0 | | | | | |
|---|---|---|---|---|---|
| | PE2 (lb/year) | ÷ | 4 qtr/year | = | PE2 (lb/qtr) |
| $NO_X$ | 4,583 | ÷ | 4 qtr/year | = | 1,145.8 |
| $SO_X$ | 1,134 | ÷ | 4 qtr/year | = | 283.5 |
| $PM_{10}$ | 1,985 | ÷ | 4 qtr/year | = | 496.3 |
| CO | 50,818 | ÷ | 4 qtr/year | = | 12,704.5 |
| VOC | 3,185 | ÷ | 4 qtr/year | = | 796.3 |

| Quarterly NEC [QNEC] S-8637-2-0 & -3-0 | | | | | |
|---|---|---|---|---|---|
| | PE2 (lb/qtr) | - | PE1 (lb/qtr) | = | NEC (lb/qtr) |
| $NO_X$ | 1,145.8 | - | 0.0 | = | 1,145.8 |
| $SO_X$ | 283.5 | - | 0.0 | = | 283.5 |
| $PM_{10}$ | 496.3 | - | 0.0 | = | 496.3 |
| CO | 12,704.5 | - | 0.0 | = | 12,704.5 |
| VOC | 796.3 | - | 0.0 | = | 796.3 |

# APPENDIX B

## BACT Analysis for Digester Gas-Fired IC Engines

# SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

## Waste Gas-Fired IC Engine**

| Pollutant | Achieved in Practice or contained in SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| $NO_X$ | 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) | | 1. Fuel Cells (<0.05 lb/MW-hr)<br>2. Microturbines (<9 ppmv @ 15% $O_2$)<br>3. Gas Turbine (<9 ppmv @ 15% $O_2$) *(Note: gas turbines only ABE for projects ≥ 3 MW)* |
| $SO_X$ | Sulfur content of fuel gas ≤ 40 ppmv (as $H_2S$) (dry absorption, wet absorption, chemical $H_2S$ reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance) | | |
| $PM_{10}$ | Sulfur content of fuel gas ≤ 40 ppmv (as $H_2S$) | | |
| CO | 2.0 g/bhp-hr | | 1. Fuel Cells (<0.10 lb/MW-hr)<br>2. Microturbines (<60 ppmv @ 15% $O_2$)<br>3. Gas Turbine (<60 ppmv @ 15% $O_2$) *(Note: gas turbines only ABE for projects ≥ 3 MW)* |
| VOC | 0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent) | | Fuel Cells (<0.02 lb-VOC/MW-hr as $CH_4$) |
| Ammonia ($NH_3$) Slip | ≤ 10 ppmv @ 15% $O_2$ | | |

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

**3.3.15**

# Top-Down BACT Analysis for Project S-1143770
# Digester Gas-Fired IC Engines

Current District BACT Guideline 3.3.15 applies to the proposed waste gas-fired IC engines. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engines proposed under this project.

## I. Proposal and Process Description

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kWe. The covered lagoon digester will utilize an air injection system for biological removal of $H_2S$ from the digester gas. After initial removal of $H_2S$ in the covered lagoon digester, the digester gas will be captured by the covered the lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional $H_2S$ by an iron sponge scrubber and/or activated carbon or an equivalent $H_2S$ removal system and for removal of moisture. The cleaned digester gas, which consists mostly of methane, the main component of natural gas, will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system.

## II. BACT Applicability

**New emissions units – PE > 2.0 lb/day**

| New Emissions Unit BACT Applicability for S-8637-2-0 & -3-0 After Commissioning | | | | |
|---|---|---|---|---|
| Pollutant | PE2 for each unit after commissioning (lb/day) | BACT Threshold (lb/day) | SSPE2 (lb/yr) | BACT Triggered? |
| $NO_X$ | 11.7 | > 2.0 | N/A | **Yes** |
| $SO_X$ | 3.1 | > 2.0 | N/A | **Yes** |
| $PM_{10}$ | 5.4 | > 2.0 | N/A | **Yes** |
| CO | 135.9 | > 2.0 and SSPE2 ≥ 200,000 lb/yr | 101,636 | No |
| VOC | 7.8 | > 2.0 | N/A | **Yes** |
| $NH_3$ | 3.9 | > 2.0 | N/A | **Yes** |

* BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

## III. Top-Down BACT Analyses for the Digester Gas-Fired Engines

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed digester gas-fired IC engines under this project.

### 1. BACT Analysis for $NO_X$ Emissions:

#### a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce $NO_X$ emissions from waste gas-fired IC engines:

1) $NO_X$ emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cell (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbine (< 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)

Description of Control Technologies

**1) $NO_X$ emissions ≤ 0.15 g/bhp-hr (9-11 ppmv $NO_X$ @ 15% $O_2$) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)**

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce $NO_X$, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the $NO_X$ emissions by up to 90%.

**2) Fuel Cell (≤ 0.05 lb- $NO_X$/MW-hr ≈ 1.5 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)**

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of $CO_2$ that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

**3) Gas Turbine (< 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)**

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, $NO_X$ emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

**4) Microturbine (< 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)**

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[5] Microturbines generally have electrical efficiencies

[5] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of $NO_X$, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low $NO_X$, or DLN) combustion technology. Microturbines manufacturers will generally guarantee $NO_X$ emissions of 9-15 ppmv @ 15% $O_2$. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[6], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 4) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

**b. Step 2 - Eliminate technologically infeasible options**

Option 3 - Gas Turbine (≤ 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

The proposed project would require gas turbines rated 1,059 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

**c. Step 3 - Rank remaining options by control effectiveness**

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) $NO_X$ emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. The lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.d: 65 ppmvd $NO_X$ (or 90% reduction), 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% $O_2$). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% $O_2$ reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

<u>Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)</u>

Because fuel cells have reduced $NO_X$ and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engines with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

**Assumptions**

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[9] *in February 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day ($1,468\ bhp_{out}/engine \times 1\ bhp_{in}/0.33\ bhp_{out} \times 2,545\ Btu_{in}/bhp_{in}\text{-}hr \times 1\ MMBtu/10^6\ Btu \times 24\ hr/day \times 1\ engine$)
- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year ($1,468\ bhp_{out}/engine \times 1\ bhp_{in}/0.33\ bhp_{out} \times 2,545\ Btu_{in}/bhp_{in}\text{-}hr \times 1\ MMBtu/10^6\ Btu \times 8,760\ hr/year \times 1\ engine$)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

[9] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines must be limited to a sulfur content of no more than 40 ppmv as $H_2S$ to satisfy BACT for $SO_X$. Because required level of sulfur removal is adequate for use in the engines, there will be no increase in operating costs related to cleaning the digester gas for use in IC engines.
- Rule 4702 $NO_X$ emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% $O_2$ = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% $O_2$ as $CH_4$ = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% $O_2$ reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace each proposed engine: 1,500 kW (estimated based on 271.71 MMBtu/day and 45% efficiency)
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,550/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: <u>http://www.wbdg.org/resources/fuelcell.php</u>) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $5,113/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: \$0.19/kW-hr
- Fuel Cell $NO_X$ emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-$NO_X$/MW-hr but measured emissions from fuel cells are generally much lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% $O_2$ as $CH_4$ based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engines with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a fuel cell power plant is calculated as follows:

(1,500 kW x \$5,113/kW) - (1,059 kW x \$2,139/kW) = \$5,404,299

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

A = $[P \times i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

A = $[\$5,404,299 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$879,525/year**

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

Fuel Cells (Alternate Equipment)
271.71 MMBtu/day x $10^6$ Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 1,493 kW

99,175.4 MMBtu/yr x $10^6$ Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 13,076,159 kW-hr /year

Cost Decrease from Increased Revenue for Power Generation from Replacing each Proposed 1,059 kW Engine with a Fuel Cell
(9,276,840 kW-hr/yr - 13,076,159 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$485,249/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 IC kW Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Fuel Cells (Alternate Equipment)
13,076,159 kW-hr/yr x $0.19/kW-hr = $2,484,470/year

Annual Costs of Increased Maintenance
$2,484,470/yr - $185,537/yr = $2,298,933/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Each Proposed Engine

$879,525/year + (-$485,249/year) + $2,298,933/year = **$2,693,209/year**

Emission Reductions:

NO$_X$ and VOC Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO$_X$ emissions from the engines will be based on the NO$_X$ emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO$_X$/MMBtu (65 ppmv NO$_X$ @ 15% $O_2$) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO$_X$/MW-hr and 0.02 lb-VOC/MW-hr as $CH_4$

Emission Reductions:

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO$_X$ Emission Reductions (65 ppmv @ 15% $O_2$ → 0.01 lb-NO$_X$/MW-hr)
(99,175.4 MMBtu/yr x 0.2540 lb-NO$_X$/MMBtu) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO$_X$/MW)
= 25,060 lb-NO$_X$/year (12.53 ton-NO$_X$/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,468 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW)
= 28,089 lb-VOC/year (14.04 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO$_X$ and VOC Reductions based on District Standard Emission Reductions

(12.53 ton-NO$_X$/year x \$24,500/ton-NO$_X$) + (14.04 ton-VOC/year x \$17,500/ton-VOC)
= **\$552,685/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO$_X$ and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines ($\leq$ 9 ppmv $NO_X$ @ 15% $O_2$) (Alternate Basic Equipment)

The cost analysis below demonstrates that the $NO_X$ emission reductions achieved by replacement of the proposed engines with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).

In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in $NO_X$ emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed $NO_X$ emissions rate of 9 ppmvd @ 15% $O_2$ for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-$NO_X$/hp-hr.[10] This level is not significantly different than the current BACT requirement for waste gas-fired engines of 0.15 g-$NO_X$/bhp-hr.

The following discussion demonstrates how the difference the efficiency of engines and microturbines can affect the emission rate. $NO_X$ emissions from the engines will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv $NO_X$ @ 15% $O_2$). Microturbine suppliers will generally guarantee $NO_X$ emissions $\leq$ 9 ppmv @ 15% $O_2$ For digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of each of the proposed 1,059 kW engines is between 27-36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26-28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21-28%.

The maximum expected $NO_X$ emission factor for the proposed engine-generator sets is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv $NO_X$ @ 15% O2 and the expected range of microturbine electrical conversion efficiency given above, the $NO_X$ emission factor from large digester gas-

[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd $NO_X$ @ 15% $O_2$ from smaller units will actually be higher than 0.15 g-$NO_X$/bhp-hr

[11] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[12] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because, the maximum $NO_X$ emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

**Assumptions**

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as $H_2S$ to satisfy BACT for $SO_X$. Because required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- Price for electricity: $127.72/MW-hr (based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)[9] in February 2016)

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day ($1{,}468\ bhp_{out}/engine \times 1\ bhp_{in}/0.33\ bhp_{out} \times 2{,}545\ Btu_{in}/bhp_{in}\text{-}hr \times 1\ MMBtu/10^6\ Btu \times 24\ hr/day \times 1\ engine$)

- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 $bhp_{out}$/engine x 1 $bhp_{in}$/0.33 $bhp_{out}$ x 2,545 $Btu_{in}$/$bhp_{in}$-hr x 1 MMBtu/$10^6$ Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 $NO_X$ emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% $O_2$ = 0.2540 lb/MMBtu

Assumptions for Microturbines

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 24.5% (*conservative estimate, SGIP metered data indicates an efficiency of 21%*)
- Estimated Size of microturbine system needed to replace each engine: 950 kW net (1,000 kW nominal capacity)
- Estimated Purchase and Installation Cost for 950 kW net (1,000 kW nominal capacity) microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system rated 950 kW net (1,000 kW nominal capacity): $3,244/kW
- Typical operation costs for a 950 kW net (1,000 kW nominal capacity) microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- $NO_X$ Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv $NO_X$ @ 15% $O_2$ (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The estimated increased incremental capital cost for replacement of each the proposed engines with microturbines is calculated based on the difference in cost of a microturbine system and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a microturbine system is calculated as follows:

(950 kW x $3,244/kW) - (1,059 kW x $2,139/kW) = $816,599

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$816,599 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$132,898/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

950 kW (net) Microturbine Package (Alternate Equipment)
271.71 MMBtu/day x $10^6$ Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 813 kW

99,175.4 MMBtu/yr x $10^6$ Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 7,119,242 kW-hr /year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,059 kW Engine with Microturbines
(9,276,840 kW-hr/yr - 7,119,242 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = $275,568/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 kW IC Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Microturbines (Alternate Equipment)
7,119,242 kW-hr/yr x $0.012/kW-hr = $85,431/year

Cost from Annual Decrease in Maintenance Costs
$85,431/yr - $185,537/yr = -$100,106/year

Total Increased Annual Costs for Microturbines as an Alternative to Each Proposed Engine

$132,898/year + $275,568/year + (-$100,106/year) = **$308,360/year**

Emission Reductions:

$NO_X$ Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for $NO_X$ emissions from the engines will be based on the $NO_X$ emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-$NO_X$/MMBtu (65 ppmv $NO_X$ @ 15% $O_2$)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-$NO_X$/MMBtu (9 ppmv $NO_X$ @ 15% $O_2$)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

$NO_X$ Emission Reductions (65 ppmv @ 15% $O_2$ → 9 ppmv @ 15% $O_2$)
99,175.4 MMBtu/yr x (0.2540 lb-$NO_X$/MMBtu – 0.0352 lb-$NO_X$/MMBtu)
= 21,700 lb-$NO_X$/year (10.85 ton-$NO_X$/year)

Cost of $NO_X$ Emission Reductions

Cost of reductions = ($308,360/year)/[(21,700 lb-$NO_X$/year)(1 ton/2000 lb)]
= **$28,420/ton of $NO_X$ reduced**

As shown above, the cost of the $NO_X$ emission reductions for replacing each of the proposed engines with microturbines exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 3: $NO_X$ emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

**e. Step 5 - Select BACT**

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: $NO_X$: $NO_X$ emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce $NO_X$ emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

**2. BACT Analysis for $SO_X$ Emissions:**

**a. Step 1 - Identify all control technologies**

The following options were identified to reduce $SO_X$ emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as $H_2S$ (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

**b. Step 2 - Eliminate technologically infeasible options**

There are no technologically infeasible options to eliminate from step 1.

**c. Step 3 - Rank remaining options by control effectiveness**

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as $H_2S$ (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

**e. Step 5 - Select BACT**

Pursuant to the above BACT Analysis, BACT for $SO_X$ emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as $H_2S$. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as $H_2S$. Therefore, the BACT requirements for $SO_X$ are satisfied.

3. **BACT Analysis for $PM_{10}$ Emissions:**

**a. Step 1 - Identify all control technologies**

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and $CO_2$ (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly $H_2S$) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as $H_2S$ (Achieved in Practice)

**b. Step 2 - Eliminate technologically infeasible options**

There are no technologically infeasible options to eliminate from step 1.

**c. Step 3 - Rank remaining options by control effectiveness**

1) Sulfur Content of fuel gas ≤ 40 ppmv as $H_2S$ (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

**e. Step 5 - Select BACT**

Pursuant to the above BACT Analysis, BACT for $PM_{10}$ emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as $H_2S$. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as $H_2S$. Therefore, the BACT requirements for $SO_X$ are satisfied.

**4. BACT Analysis for VOC Emissions:**

**a. Step 1 - Identify all control technologies**

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

**b. Step 2 - Eliminate technologically infeasible options**

There are no technologically infeasible options to eliminate from step 1.

**c. Step 3 - Rank remaining options by control effectiveness**

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as $CH_4$) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the $NO_X$ and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the $NO_X$ and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

**e. Step 5 - Select BACT**

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

**5. BACT Analysis for $NH_3$ Slip Emissions:**

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce $NO_X$, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the $NO_X$ emissions by up to 90%. Ammonia slip is the result of unreacted ammonia exiting the SCR system.

**a. Step 1 - Identify all control technologies**

The District has not established a cost effectiveness threshold for ammonia. Therefore, only options that are determined to be Achieved-in-Practice controls will be considered for ammonia in this analysis.

District BACT Guideline 3.3.15 lists an ammonia slip emission limit of 10 ppmvd @ 15% $O_2$ as an Achieved in Practice BACT requirement for waste gas-fired IC engines.

1) $NH_3$ emissions ≤ 10 ppmvd @ 15% $O_2$ (Achieved in Practice)

**b. Step 2 - Eliminate technologically infeasible options**

There are no technologically infeasible options to eliminate from step 1.

**c. Step 3 - Rank remaining options by control effectiveness**

1) $NH_3$ emissions ≤ 10 ppmvd @ 15% $O_2$ (Achieved in Practice)

**d. Step 4 - Cost Effectiveness Analysis**

The only option above is achieved in practice and has been proposed by the applicant. Additionally, as stated above, a cost effectiveness threshold for ammonia has not been established by the District. Therefore a cost analysis is not required.

**e. Step 5 - Select BACT**

Pursuant to the above BACT Analysis, BACT for $NH_3$ slip emissions from the proposed engines is $NH_3$ slip emissions ≤ 10 ppmvd @ 15% $O_2$. The applicant has proposed IC engines with $NH_3$ slip emissions ≤ 10 ppmvd @ 15% $O_2$. Therefore, the BACT requirements for $NH_3$ slip are satisfied.

# APPENDIX C

## Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)

# San Joaquin Valley Air Pollution Control District
# *REVISED* Risk Management Review

| | |
|---|---|
| To: | Ramon Norman – Permit Services |
| From: | Yu Vu – Technical Services |
| Date: | October 22, 2015 |
| Facility Name: | ABEC #3 dba Lakeview Dairy Biogas |
| Location: | 17702 Bear Mountain Blvd, Bakersfield, CA 93311<br>at Lakeview Dairy (S-5254) |
| Application #(s): | S-8637-2-0, 3-0 |
| Project #: | S-1143770 |

## A. RMR SUMMARY

| RMR Summary | | | |
|---|---|---|---|
| **Categories** | **1,468 BHP Bio Gas Engines (Unit 2-0 & 3-0)** | **Project Totals** | **Facility Totals** |
| **Prioritization Score** | 107 (ea.) | 214 | >1 |
| **Acute Hazard Index** | 0.48 (ea.)[1] | 0.95 | 0.95 |
| **Chronic Hazard Index** | 0.16 (ea.) | 0.31 | 0.31 |
| **Maximum Individual Cancer Risk ($10^{-6}$)** | 0.002 (ea.) | 0.004 | 0.004 |
| **T-BACT Required?** | **No** | | |
| **Special Permit Conditions?** | **Yes** | | |

[1] $H_2S$ emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

**Proposed Permit Conditions**

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

Unit # 2-0, 3-0

1) The $H_2S$ emissions from the engine shall not exceed 1.97 lbs/hr. as determined by source testing. [District Rule 2201]

## B. RMR REPORT

### I. Project Description

Technical Services received a request on October 7, 2015, to perform a revised Risk Management Review for a proposed installation of two 1,468 BHP Dairy Bio gas-fired full time IC engines. Per the project engineer, the following changes to the project were made in this revision:

1) An increase in each engine's rating from 1,412 bhp to 1,468 bhp.
2) An increase in digester gas consumption of each engine from 16,303 scf/hr and 142,812,528 scf/yr to 16,327 scf/hr and 143,024,520 scf/yr.
3) A change in the stack parameters, resulting in the stack exit velocity of each engine increasing from 19.766 m/s to 23.636 m/s.

### II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using District approved Dairy Bio Gas emission factors for internal combustion were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

| Analysis Parameters<br>Unit 2-0, 3-0 | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 9.144 | **Closest Receptor (m)** | Various |
| **Stack Diameter. (m)** | 0.4572 | **Type of Receptor** | Business |
| **Stack Exit Velocity (m/s)** | 23.636 | **Max Hours per Year** | 8,760 |
| **Stack Exit Temp. (°K)** | 699.817 | **Fuel Type** | Dairy Bio Gas |
| **BHP** | 1,468 | | |

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and $PM_{10}$; as well as a RMR. The emission rates used for criteria pollutant modeling were:

| Pollutant | lb/hr | lb/yr |
|---|---|---|
| CO | 15.6966 | 50,818 |
| $NO_x$ | 3.2364 | 4,582.7 |
| $SO_x$ | 0.1295 | 1,134.0 |
| $PM_{10}$ | 0.2265 | 1,984.6 |
| $H_2S$ | 6.0834 | N/A |

The results from the Criteria Pollutant Modeling are as follows:

**Criteria Pollutant Modeling Results***

| Bio-Gas Engine | 1 Hour | 3 Hours | 8 Hours | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_x$ | Pass[1] | X | X | X | Pass |
| $SO_x$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass[2] | Pass[2] |
| $H_2S$ | Pass[3] | X | X | X | X |

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]$H_2S$ emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

## III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

## IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

# APPENDIX D
## Draft ATCs
## (S-8637-1-0, -2-0, & -3-0)

# FOR PROJECT FILE
## Emissions Profiles

# San Joaquin Valley
# Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** S-8637-1-0 **ISSUANCE DATE:** DRAFT

DRAFT

**LEGAL OWNER OR OPERATOR:** ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
**MAILING ADDRESS:** 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

**LOCATION:** 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

**EQUIPMENT DESCRIPTION:**
ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

## CONDITIONS

1. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
4. The digester system cover(s) shall be designed and installed in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 - Roofs and Covers. [District Rule 2201]
5. The digester system shall be designed to allow gas generated during summer conditions to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
6. The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
7. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services
S-8637-1-0 Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

8. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

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San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** S-8637-2-0 **ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
**MAILING ADDRESS:** 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

**LOCATION:** 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

**EQUIPMENT DESCRIPTION:**
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

## CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

**YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT.** This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services
S-8637-2-0 : Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as $H_2S$. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]



CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]



CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

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San Joaquin Valley
Air Pollution Control District

# AUTHORITY TO CONSTRUCT

**PERMIT NO:** S-8637-3-0 **ISSUANCE DATE:** DRAFT

**LEGAL OWNER OR OPERATOR:** ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
**MAILING ADDRESS:** 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

**LOCATION:** 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

**EQUIPMENT DESCRIPTION:**
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

## CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

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Seyed Sadredin, Executive Director / APCO

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9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]



CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

# ATTACHMENT O

Application No. B0104

# Staff Summary

**California Bioenergy LLC**
**ABEC #3 LLC dba Lakeview Farms Dairy Biogas, Bakersfield, CA**
**Electricity from Dairy Manure Biogas**

**Intermediate Facility:**
Lakeview Farms Dairy, Bakersfield, CA

Deemed Complete: 5/15/2020
Posted for Comment: 11/9/2020
Certified: TBD
CI Effective: TBD

## Pathway Summary

California Bioenergy LLC seeks certification of a Tier 2 pathway for electricity from dairy manure biogas produced by a reciprocating internal combustion (IC) engine and generator at the ABEC #3 LLC dba Lakeview Farms Dairy Biogas (ABEC #3) and supplied to the California electricity grid for use in transportation using book-and-claim accounting for low-CI electricity.[1]

The covered lagoon digester captures methane that would otherwise be vented to the atmosphere. The ABEC #3 digester is registered with the Climate Action Reserve (CAR1316/CALS6316; listed date: 09/05/2018; crediting period expiration: 12/31/2027) and has previously generated ARB Offset Credits under California's Cap & Trade program.

The dairy has an average cattle population of about 9,000. In the baseline scenario, manure is either collected via a flush system or left in a dry lot. For the baseline, manure from open lot corrals and milking parlor was collected via flush and scraped for heifers in open lot corrals. Flushed manure was sent to anaerobic storage after solids separation using a stationary screen with a portion of the manure collected from milking cows in open lot corral sent directly to anaerobic storage. Separated solids and scrapped manure was piled in open lots and exported off farm on an annual basis. Prior to installation of the digester, incomplete removal of volatile solids (VS) occurred annually in the anaerobic storage and as a result, no lagoon cleanouts were modeled.

[1] All citations to the LCFS Regulation are found in Title 17, California Code of Regulations (CCR), section 95480-95503. Book-and-claim accounting for low-CI electricity is primarily addressed in section 95488.8(i) of the LCFS Regulation.

With the installation of the project, manure that was sent to anaerobic storage was diverted to the digester. Additionally, manure from heifers in open lot corrals was collected via vacuum and sent to the anaerobic digestion. The covered lagoon digester captures methane that would otherwise be vented to the atmosphere.

Biogas captured by the covered lagoon is either sent to a 1MW Caterpillar internal combustion engine for electricity generation or vented. The compressor draws the gas through the hydrogen sulfide ($H_2S$) removal system, which consists of an iron sponge and an activated carbon tank that reduces the $H_2S$ concentration to below air permitted levels. The internal combustion engine converts roughly one third of energy in biogas to electricity. A portion of the biogas produced by the covered lagoon digester that is not destroyed by the engine generator is vented rather than flared. This vented methane is separately metered and included in the pathway emissions in the Simplified Calculator. Grid and on-site generated electricity is used to power the mixers in the digester, blowers to move gas through the system, electronic instrumentation, and internal combustion engine.

**Carbon Intensity of Electricity Pathway**

The CI is determined from life cycle analysis conducted using a modified version of the Board-approved Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure.[2] The calculator was modified in accordance with regulatory requirements and LCFS Guidance Document 19-06,[3] and has been determined to be equivalent to CA-GREET3.0 pursuant to section 95488.7(a)(1) of the LCFS regulation. The applicant has provided operational data and supporting documentation for assessment of baseline emissions, biogas production, electricity generation from dairy biogas, and venting for a period of 24 months, from March 2018 to February 2020.

The following table lists the proposed CI for this pathway.

[2] The Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure (August 13, 2018), incorporated by reference in the LCFS Regulation, section 95488.3(b).
[3] LCFS Guidance 19-06 (Revised October 2019): Determining Carbon Intensity of Dairy and Swine Manure Biogas to Electricity Pathways

**Proposed Pathway CI**

| Fuel & Feedstock | Pathway FPC | Pathway Description | Carbon Intensity (gCO2e/MJ) |
|---|---|---|---|
| Low-CI Electricity from Dairy Manure Biogas | TBD | Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at ABEC #2 LLC dba West Star North Dairy Biogas in Bakersfield, California for use as transportation fuel in California. | -382.98 |

**Operating Conditions**

The certified CI value in the above table may be used to report and generate credits for fuel quantities that are produced at the facility in the manner described in the applicant's Life Cycle Analysis (LCA) report, and dispensed for transportation use in California, subject to the following requirements and conditions:

1. Fuel pathway holders are subject to the requirements of the California Air Resources Board's (CARB) Low Carbon Fuel Standard (LCFS) regulation, which appears at sections 95480 to 95503 of title 17, California Code of Regulations. Requirements include ongoing monitoring, reporting, recordkeeping, and third-party verification of operational CI and a controlled process for providing product transfer documents or other similar records to counterparties or CARB.

2. No later than October 1, 2020, equipment to continuously measure and record methane concentration in biogas at least every 15 minutes must be installed to report the monthly weighted average methane concentration in fields 2.5 and 2.7 in the Annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

3. To confirm compliance with LCFS Regulation section 95488.8(h) and demonstrate use of directly supplied low-CI process energy in annual Fuel Pathway Reports, the fuel pathway holder must demonstrate retirement of the corresponding quantity of Renewable Electricity Certificates (RECs) that were generated for the quantity of low-CI electricity consumed within the fuel pathway (use of onsite electricity from biogas in field 2.17). For each quarter of operation, the number of RECs that are associated with process energy must be retired in a WREGIS retirement sub-account named "Low-CI Process Energy at LCFS Facility [ID number]", where the LCFS Facility ID is the number assigned in the AFP at the time of facility registration. These RECs and the associated environmental attributes can no longer be sold, transferred, or claimed by any entity or for any other purpose. The WREGIS report demonstrating REC retirement must be downloaded from WREGIS and uploaded to the AFP as part

of each annual Fuel Pathway Report to demonstrate the quantity of electricity from biogas that is consumed within the fuel pathway and claimed to lower the CI of the produced fuel.

Note that this retirement account for process energy is distinct from and in addition to the requirement for any fuel reporting entity claiming electricity as supplied for use as transportation fuel in the LRT under this pathway to demonstrate quarterly REC retirement as part of each quarterly report.

4. The electricity, including the environmental attributes associated with the electricity, claimed under this pathway shall not be claimed under any other program notwithstanding the exceptions listed in LCFS Regulation section 95488.8(i)(1). The LCFS places no restrictions on the use of any voluntary emissions reductions credits generated by the project for emissions that are demonstrated to be additional to reductions claimed under the LCFS.

5. The fuel pathway holder must include the assumptions and calculations used to establish the fraction of solids input to each manure management system in its annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

6. Any quantity of biomethane metered as captured that cannot be demonstrated by meter records to have been destroyed, must be calculated by energy balance and accounted for in the CI as a fugitive methane emission if the calculated value exceeds the default 2% fugitive emission.

**Staff Analysis and Recommendation**

Staff has reviewed the application and has replicated, using the Tier 2 modified version of the Simplified CI Calculator, the CI values calculated by the applicant. EcoEngineers (H3-20-008) submitted a positive validation statement. Staff recommends this application be certified after all the comments received during the 10-day comment period are addressed satisfactorily by the applicant. The certification is subject to the operating conditions set forth in this document.

# ATTACHMENT P

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

**Re: Notice of Final Determination of Compliance (FDOC)**
**Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)**

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

cc: Gary Rubenstein, Sierra Research

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

**Re: Notice of Final Determination of Compliance (FDOC)**
**Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)**

Dear Mr. Tollstrup:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

**Re: Notice of Final Determination of Compliance (FDOC)**
**Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)**

Dear Mr. Rios:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

**Re: Notice of Final Determination of Compliance (FDOC)**
**Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)**

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not significantly increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Fresno Bee

## NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

# FINAL DETERMINATION OF COMPLIANCE EVALUATION

**Avenal Power Center Project**
**California Energy Commission**
**Application for Certification Docket #: 08-AFC-01**

| | |
|---|---|
| **Facility Name:** | Avenal Power Center, LLC |
| **Mailing Address:** | 500 Dallas Street, Level 31<br>Houston, TX 77002 |
| **Contact Name:** | Jim Rexroad |
| **Telephone:** | (713) 275-6147 |
| **Fax:** | (713) 275-6115 |
| **Cell:** | (832) 748-1060 |
| **E-Mail:** | jim.Rexroad@macquarie.com |
| **Alternate Contact:** | Eric Walther |
| **Telephone:** | (916) 444-6666 |
| **Fax:** | (916) 444-8373 |
| **Cell:** | (916) 883-8774 |
| **E-Mail:** | ewalther@sierraresearch.com |
| **Alternate Contact:** | Tracey Gilliland |
| **Telephone:** | (713) 275-6148 |
| **Cell:** | (512) 217-3002 |
| **E-Mail:** | tracey.gilliland@macquarie.com |
| **Engineer:** | Derek Fukuda, Air Quality Engineer |
| **Lead Engineer:** | Joven Refuerzo, Supervising Air Quality Engineer |
| **Project #:** | C-1100751 |
| **Application #'s:** | C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1 |
| **Submitted:** | March 3, 2010 |

## Table of Contents

## I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide $NO_X$ emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of $NO_X$ (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide $NO_X$ emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

## II. APPLICABLE RULES:

| | |
|---|---|
| **Rule 1080** | Stack Monitoring (12/17/92) |
| **Rule 1081** | Source Sampling (12/16/93) |
| **Rule 1100** | Equipment Breakdown (12/17/92) |
| **Rule 2010** | Permits Required (12/17/92) |
| **Rule 2201** | New and Modified Stationary Source Review Rule (9/21/06) |
| **Rule 2520** | Federally Mandated Operating Permits (6/21/01) |
| **Rule 2540** | Acid Rain Program (11/13/97) |

**Rule 2550** Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
**Rule 4001** New Source Performance Standards (4/14/99)
Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart GG - Standards of Performance for Stationary Gas Turbines
Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
**Rule 4002** National Emissions Standards for Hazardous Air Pollutants (5/20/2004)
Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
**Rule 4101** Visible Emissions (2/17/05)
**Rule 4102** Nuisance (12/17/92)
**Rule 4201** Particulate Matter Concentration (12/17/92)
**Rule 4202** Particulate Matter Emission Rate (12/17/92)
**Rule 4301** Fuel Burning Equipment (12/17/92)
**Rule 4305** Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
**Rule 4306** Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
**Rule 4351** Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
**Rule 4701** Stationary Internal Combustion Engines – Phase 1 (8/21/03)
**Rule 4702** Stationary Internal Combustion Engines – Phase 2 (1/18/07)
**Rule 4703** Stationary Gas Turbines (9/20/07)
**Rule 4801** Sulfur Compounds (12/17/92)
**Rule 8011** General Requirements (8/19/04)
**Rule 8021** Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
**Rule 8031** Bulk Materials (8/19/04)
**Rule 8041** Carryout and Trackout (8/19/04)
**Rule 8051** Open Areas (8/19/04)
**Rule 8061** Paved and Unpaved Roads (8/19/04)
**Rule 8071** Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
**Rule 8081** Agricultural Sources (9/16/04)
**California Environmental Quality Act (CEQA)**
**California Code of Regulations (CCR)**, Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
**California Health & Safety Code (CH&S)**, Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

## III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

## IV. PROCESS DESCRIPTION:

**Combined-Cycle Combustion Turbine Generators**

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low $NO_X$ combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low $NO_X$ (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

$NO_X$: 2.0 ppmvd @ 15% $O_2$
VOC: 2.0 ppmvd @ 15% $O_2$
CO: 2.0 ppmvd @ 15% $O_2$
$SO_X$: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
$PM_{10}$: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record $NO_X$, CO, and $O_2$ concentrations in the exhaust gas for each CTG.

**Heat Recovery Steam Generators (HRSGs)**

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the

HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce $NO_X$ in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts $NO_X$ to nitrogen and water, resulting in a reduced concentration of $NO_X$ in the exhaust gases exiting the stack.

**Duct Burners**

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

**Steam Turbine Generator**

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

**Auxiliary Boiler**

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low $NO_X$ burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

**Diesel-Fired Emergency IC Engine Powering a Fire Pump**
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

**Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator**
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

## V. EQUIPMENT LISTING:

**C-3953-10-1:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

**C-3953-11-1:** 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

**C-3953-12-1:** 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

**C-3953-13-1:** 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

**C-3953-14-1:** 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

## VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

### i. C-3953-10-1 and C-3953-11-1 (Turbines)

Each CTG will be equipped with a Dry Low $NO_X$ combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low $NO_X$ combustors and a SCR system with ammonia injection can achieve a $NO_X$ emission rate of 2.0 ppmvd @ 15% $O_2$. CO emissions of 2.0 ppmvd @ 15% $O_2$ have been demonstrated with the use of an oxidation catalyst [(1)]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% $O_2$.

Emissions from natural gas-fired turbines include $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$.

$NO_X$ is the major pollutant of concern when combusting natural gas. Virtually all gas turbine $NO_X$ emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable $NO_2$ molecule. There are two mechanisms by which $NO_X$ is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal $NO_X$ and prompt $NO_X$), and 2) the conversion of nitrogen chemically bound in the fuel (fuel $NO_X$).

Thermal $NO_X$ is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt $NO_X$, a form of thermal $NO_X$, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form $NO_X$. Prompt $NO_X$ is formed in both fuel-rich flame zones and dry low $NO_X$ (DLN) combustion zones. The contribution of prompt $NO_X$ to overall $NO_X$ emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal $NO_X$ emissions in DLN combustors. For this reason prompt $NO_X$ becomes an important consideration for DLN combustor designs, and establishes a minimum $NO_X$ level attainable in lean mixtures.

Fuel $NO_X$ is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as $N_2$ in some natural gas, does not contribute significantly to fuel $NO_X$ formation. With excess air, the degree of fuel $NO_X$ formation is primarily a function of the nitrogen content in the fuel. When compared to thermal $NO_X$, fuel $NO_X$ is not currently a major contributor to overall $NO_X$ emissions from stationary gas turbines firing natural gas.

The level of $NO_X$ formation in a gas turbine, and hence the $NO_X$ emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of $NO_X$ generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

The design of the combustor is the most important factor influencing the formation of $NO_X$. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal $NO_X$ formation. Thermal $NO_X$ formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects $NO_X$ formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal $NO_X$ production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal $NO_X$ formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum $NO_X$ formation during combustion. This is known as dry low $NO_X$ (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce $NO_X$ emissions by injecting ammonia ($NH_3$) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, $NH_3$, and $O_2$ react on the surface of the catalyst to form molecular nitrogen ($N_2$) and $H_2O$. SCR is capable of over 90 percent $NO_X$ reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause $NO_X$ and $NH_3$ to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% $O_2$.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit $NO_X$ formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide ($CO_2$).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

**ii. C-3953-12-1 (Boiler)**

Emissions from natural gas-fired boilers include $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$.

$NO_X$ is the major pollutant of concern when burning natural gas. $NO_X$ formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal $NO_X$) or due to conversion of chemically bound nitrogen in the fuel (fuel $NO_X$). Due to the low fuel nitrogen content of natural gas, nearly all $NO_X$ emissions are thermal $NO_X$. Formation of thermal $NO_X$ is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal $NO_X$ with an Cleaver Brooks ultra low $NO_X$ burner. Cleaver Brooks burners reduce $NO_X$ by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt $NO_X$. This also eliminates the traditional $NO_X$ versus CO tradeoff.

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the $NO_X$ emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal $NO_X$. $NO_X$ emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces $SO_X$ emissions by approximately 99% from standard diesel fuel.

**iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)**

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on natural gas engine emissions are detailed below.

[2] From "Non-catalytic $NO_x$ Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal $NO_X$. $NO_X$ emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces $NO_X$ formation.

## VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide $NO_X$ emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All $PM_{10}$ emissions are assumed to be $PM_{2.5}$ emissions.

### i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, $PM_{10}$ and $SO_X$ during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for $NO_X$, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for $PM_{10}$, $SO_X$, and $NH_3$ are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was

operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide $NO_X$ emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for $NO_X$ are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated $NO_X$ emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide $NO_X$ emission limit; however the $NO_X$ emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide $NO_X$ emission limit. Therefore, the facility wide limit is a valid limit and the $NO_X$ emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for $PM_{10}$, $SO_X$, and $NH_3$ are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

**ii. C-3953-12-1 (Boiler)**

- External $O_2$ stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum $SO_X$ emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb $SO_X$/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x $10^6$ ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

**iv. C-3953–14-1 (Natural gas IC engine powering electrical generator)**

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily $SO_X$ emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb $SO_X$/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x $10^6$ ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

[3] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

## B. Emission Factors

### i. C-3953-10-1 and C-3953-11-1 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

| Commissioning Period Emissions | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ |
| Mass Emission Rate (per turbine, lb/hr) | 160 | 1,000 | 16 | N/A(5) | N/A(4) |

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% $O_2$), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

**Maximum Emission Rate Without Duct Burner Firing:**

The worst-case $NO_X$, $PM_{10}$, CO, VOC, and $NH_3$ mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case $SO_X$ mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

$NO_X$ Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-$NO_X$/MMBtu)
**= 13.55 lb-$NO_X$/hr**

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
**= 8.35 lb-CO/hr**

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
**= 3.34 lb-VOC/hr**

$PM_{10}$ Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-$PM_{10}$/MMBtu)
**= 8.91 lb-$PM_{10}$/hr**

[4] $PM_{10}$ and $SO_X$ emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

$SO_X$ Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-$SO_X$/MMBtu)
**= 5.23 lb-$SO_X$/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x ($2.64\times10^{-9}$) x ff x HV x FL x [20.9 / (20.9 – $O_2$%)]

Where:
ppm is the emission concentration in ppmvd @ 15% $O_2$ (10 ppmv)
MW is the molecular weight of the pollutant: ($MW_{NH3}$ = 17 lb/lb-mol)
$2.64 \times 10^{-9}$ is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
$O_2$ is the stack oxygen content to which the emission concentrations are corrected: (15%)

$NH_3$ Emission Rate (lb/hr) = 10 x 17 x ($2.64\times10^{-9}$) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
**= 25.31 lb-NH3/hr**

| **Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)** | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| Mass Emission Rates (per turbine, lb/hr) | 13.55 | 8.35 | 3.34 | 8.91 | 5.23 | 25.31 |
| ppmvd @ 15% $O_2$ limits | 2.0 | 2.0 | 1.4 | -- | -- | 10.0 |
| lb/MMBtu* | 0.0073 | 0.0045 | 0.0018 | 0.0048 | 0.00282 | -- |

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

**<u>Maximum Emission Rate With Duct Burner Firing:</u>**

The worst-case $NO_X$, $SO_X$, $PM_{10}$, CO, VOC, and $NH_3$ mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case $SO_X$ mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

$NO_X$ Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-$NO_X$/MMBtu)
**= 17.20 lb-$NO_X$/hr**

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

$PM_{10}$ Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-$PM_{10}$/MMBtu)
= **11.78 lb-$PM_{10}$/hr**

$SO_X$ Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-$SO_X$/MMBtu)
= **6.65 lb-$SO_X$/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x ($2.64 \times 10^{-9}$) x ff x HV x FL x [20.9 / (20.9 – $O_2$%)]

Where:
ppm is the emission concentration in ppmvd @ 15% $O_2$ (10 ppmv)
MW is the molecular weight of the pollutant: ($MW_{NH3}$ = 17 lb/lb-mol)
2.64 x $10^{-9}$ is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
$O_2$ is the stack oxygen content to which the emission concentrations are corrected: (15%)

$NH_3$ Emission Rate (lb/hr) = 10 x 17 x ($2.64 \times 10^{-9}$) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
**= 32.13 lb-NH3/hr**

| **Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)** | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| Mass Emission Rates (per turbine, lb/hr) | 17.20 | 10.60 | 5.89 | 11.78 | 6.65 | 32.13 |
| ppmvd @ 15% $O_2$ limits | 2.0 | 2.0 | 2.0 | -- | -- | 10.0 |
| lb/MMBtu* | 0.0074 | 0.0045 | 0.0025 | 0.0050 | 0.00282 | -- |

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

| Startup and Shutdown Emissions | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ |
| Maximum Mass Emission Rate (per turbine, lb/hr) | 160 | 1,000 | 16 | N/A(6) | N/A[5] |
| Average Mass Emission Rate (per turbine, lb/hr) | 80 | 900 | 16 | N/A(6) | N/A(6) |

**ii. C-3953-12-1 (Boiler)**

For the new boiler, the emissions factors for $NO_X$, CO, VOC, and $PM_{10}$ are provided by the applicant. The $SO_X$ emission factor is calculated as shown below.

| Boiler Emission Factors* | | |
|---|---|---|
| Pollutant | ppmv @ 3%$O_2$ | lb/MMBtu |
| $NO_X$ | 9.0 | 0.011 |
| CO | 50.0 | 0.037 |
| VOC | 10.0 | 0.0043 |
| $PM_{10}$ | -- | 0.005 |
| $SO_X$** | -- | 0.00282 |

*Note: lb/MMBtu equivalent of ppmv values @ 3% $O_2$ as provided by the Applicant
** $SO_X$ emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr-S~~/100 ~~dscf~~ x 1 ~~lb-S~~/7000 ~~gr~~ x 64 lb $SO_X$/32 ~~lb-S~~ x 1 ~~scf~~/1013 ~~Btu~~ x $10^6$ ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for $NO_X$, CO, VOC, and $PM_{10}$ are provided by the applicant and are guaranteed by the engine manufacturer. The $SO_X$ emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

| Diesel-fired IC Engine Emission Factors | | |
|---|---|---|
| | g/hp·hr | Source |
| $NO_X$ | 3.4 | Engine Manufacturer |
| CO | 0.447 | Engine Manufacturer |
| VOC | 0.38 | Engine Manufacturer |
| $PM_{10}$ | 0.059 | Engine Manufacturer |
| *$SO_X$ | 0.005 | Mass Balance Equation Below |

[5] $PM_{10}$ and $SO_X$ emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\, lb \cdot fuel}{gallon} \times \frac{2\, lb \cdot SO_2}{1\, lb \cdot S} \times \frac{1\, gal}{137{,}000\, Btu} \times \frac{1\, hp\ input}{0.35\, hp\ out} \times \frac{2{,}542.5\, Btu}{hp \cdot hr} \times \frac{453.6\, g}{lb} = 0.005\, \frac{g\, SOx}{hp \cdot hr}$$

### iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for $NO_X$, CO, VOC, and $PM_{10}$ are provided by the applicant and are guaranteed by the engine manufacturer. The $SO_X$ emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

| Natural Gas-fired IC Engine Emission Factors | | |
|---|---|---|
| | g/hp·hr | Source |
| $NO_X$ | 1.0 | Engine Manufacturer |
| CO | 0.6 | Engine Manufacturer |
| VOC | 0.33 | Engine Manufacturer |
| $PM_{10}$ | 0.034 | Engine Manufacturer |
| **$SO_X$ | 0.0094 | Mass Balance Equation Below |

**$SO_X$ is calculated as follows:

$$0.00285\ \frac{lb - SO_x}{MMBtu} \times \frac{1\, MMBtu}{1{,}000{,}000\, Btu} \times \frac{2{,}542.5\, Btu}{bhp - hr} \times \frac{1\, bhp\ input}{0.35\, bhp\ out} \times \frac{453.6\, g}{lb} = 0.0094\ \frac{g - SO_x}{bhp - hr}$$

## C. <u>Calculations</u>

### 1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

### 2. Post Project Potential to Emit (PE2):

### i. C-3953-10-1 and C-3953-11-1 (Turbines)

#### *a. Maximum Hourly PE*

The maximum hourly potential to emit for $NO_X$, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

| **Maximum Hourly Potential to Emit** | | | | | |
|---|---|---|---|---|---|
| | Maximum Startup/Shutdown Emissions (lb/hr) | Turbine w/ Duct Burner Emissions Rate | Turbine #1 Emissions (lb/hr) | Turbine #2 Emissions (lb/hr) | Maximum Hourly Emissions for Both Turbines |
| $NO_X$ | 160 | 17.20 | 13.55 | 13.55 | 240.00 |
| CO | 1,000 | 10.60 | 8.35 | 8.35 | 1,902.00 |
| VOC | 16 | 5.89 | 3.34 | 3.34 | 32.00 |
| $PM_{10}$ | N/A[6] | 11.78 | 8.91 | 8.91 | 23.56 |
| $SO_X$ | N/A[7] | 6.65 | 5.23 | 5.23 | 13.30 |
| $NH_3$ | N/A | 32.13 | 25.31 | 25.31 | 64.26 |

***b. Maximum Daily PE***

Maximum daily emissions for $NO_X$, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for $PM_{10}$, $SO_X$, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for $PM_{10}$, $SO_X$, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

| **Maximum Daily Potential to Emit (w/ Startup and Shutdown)** | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (101° F) | Emissions Rate @ 100% Load without duct burner (32° F) | DEL (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 17.20 lb/hr | 13.03 lb/hr | 789.6 lb/day |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 5,590.8 lb/day |
| VOC | 16 lb/hr (avg) | 5.89 lb/hr | 3.34 lb/hr | 202.0 lb/day |
| $PM_{10}$ | N/A[7] | 11.78 lb/hr | 8.91 lb/hr | 282.7 lb/day |
| $SO_X$ | N/A[7] | 6.65 lb/hr | 5.23 lb/hr | 159.6 lb/day |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 771.1 lb/day |

[6] $PM_{10}$ and $SO_X$ emissions during startups and shutdowns are lower than maximum hourly emissions.

### c. *Maximum Annual PE*

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The $SO_X$ emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$SO_X$ EF = (0.36 ~~gr S~~/100 ~~dscf~~) x (1 ~~lb S~~/7000 ~~gr~~) x (64 lb $SO_X$/32 ~~lb S~~) x (1 ~~scf~~/1013 ~~Btu~~) x ($10^6$ ~~Btu~~/MMBtu)
**= 0.001 lb-$SO_X$/MMBtu**

<u>CTG w/o Duct Burner Firing:</u>
$SO_X$ Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-$SO_X$/MMBtu)
**= 1.86 lb-$SO_X$/hr**

<u>CTG w/ Duct Burner Firing:</u>
$SO_X$ Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-$SO_X$/MMBtu)
**= 2.36 lb-$SO_X$/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

**<u>Scenario 1) Weekend and Weekday Hot Start:</u>**

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for $PM_{10}$, $SO_X$, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start* | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG)) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | **143,951 lb/year** |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 557,033 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | **34,489 lb/year** |
| $PM_{10}$ | N/A(7) | 11.27 lb/hr | 9.00 lb/hr | 74,091 lb/year |
| $SO_X$ | N/A(7) | 2.36 lb/hr | 1.86 lb/hr | 15,337 lb/year |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 208,708 lb/year |

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

**Scenario 2) Weekend Shutdown and Weekday Hot Start:**

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for $PM_{10}$, $SO_X$, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start* | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | 112,506 lb/year |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 601,810 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | 26,574 lb/year |
| $PM_{10}$ | N/A(7) | 11.27 lb/hr | 9.00 lb/hr | 48,832 lb/year |
| $SO_X$ | N/A(7) | 2.36 lb/hr | 1.86 lb/hr | 10,117 lb/year |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 137,675 lb/year |

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

**Scenario 3) Baseload:**

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| **Annual Potential to Emit Baseload Scenario*** | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | 116,791 lb/year |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 74,946 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | 29,777 lb/year |
| $PM_{10}$ | N/A(7) | 11.27 lb/hr | 9.00 lb/hr | **80,656 lb/year** |
| $SO_X$ | N/A(7) | 2.36 lb/hr | 1.86 lb/hr | **16,694 lb/year** |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | **219,972 lb/year** |

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

**Maximum Annual Potential to Emit:**

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

| **Maximum Annual Potential to Emit** | | |
|---|---|---|
| | Annual PE (per CTG) | Scenario |
| $NO_X$ | 143,951 lb/year | Scenario 1 |
| CO | 197,928 lb/year | Facility Wide Limit |
| VOC | 34,489 lb/year | Scenario 2 |
| $PM_{10}$ | 80,656 lb/year | Scenario 3 |
| $SO_X$ | 16,694 lb/year | Scenario 3 |
| $NH_3$ | 219,972 lb/year | Scenario 3 |

### d. *Maximum Quarterly PE*

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

| **Maximum Quarterly Potential to Emit** | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ | CO | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| 1st Quarter | 35,987.75 | 49,482 | 8,622.25 | 20,164 | 4,173.5 | 54,993 |
| 2nd Quarter | 35,987.75 | 49,482 | 8,622.25 | 20,164 | 4,173.5 | 54,993 |
| 3rd Quarter | 35,987.75 | 49,482 | 8,622.25 | 20,164 | 4,173.5 | 54,993 |
| 4th Quarter | 35,987.75 | 49,482 | 8,622.25 | 20,164 | 4,173.5 | 54,993 |

**ii. C-3953-12-1 (Boiler)**

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

$PE_{NOx}$ = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb $NO_X$/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb $NO_X$/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb $NO_X$/year**

= (513 lb $NO_X$/year) ÷ (4 qtr/year)
= **128 lb $NO_X$/qtr**

$PE_{CO}$ = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

$PE_{VOC}$ = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

$PE_{PM10}$ = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb $PM_{10}$/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb $PM_{10}$/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb $PM_{10}$/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb $PM_{10}$/qtr**

$PE_{SOx}$ = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb $SO_X$/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb $SO_X$/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb $SO_X$/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb $SO_X$/qtr**

| **Post Project Potential to Emit (PE2) (C-3953-12-1)** | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $NO_X$ | 0.41 | 4.9 | 128 | 513 |
| CO | 1.38 | 16.6 | 432 | 1,727 |
| VOC | 0.16 | 1.9 | 50 | 201 |
| $PM_{10}$ | 0.19 | 2.2 | 58 | 233 |
| $SO_X$ | 0.11 | 1.3 | 33 | 132 |

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

$PE_{NOx}$ = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb $NO_X$/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb $NO_X$/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb $NO_X$/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb $NO_X$/year**

$PE_{CO}$ = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

$PE_{VOC}$ = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

$PE_{PM10}$ = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb $PM_{10}$/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb $PM_{10}$/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb $PM_{10}$/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb $PM_{10}$/year**

$PE_{SOx}$ = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb $SO_X$/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb $SO_X$/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb $SO_X$/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb $SO_X$/year**

| **Post Project Potential to Emit (PE2) (C-3953-13-1)** | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $NO_X$ | 2.16 | 51.8 | 27 | 108 |
| CO | 0.28 | 6.8 | 4 | 14 |
| VOC | 0.24 | 5.8 | 3 | 12 |
| $PM_{10}$ | 0.04 | 0.9 | 0.5 | 2 |
| $SO_X$ | 0.00 | 0.1 | 0 | 0 |

**iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)**

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

$PE_{NOx}$ = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb $NO_X$/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb $NO_X$/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb $NO_X$/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb $NO_X$/year**

$PE_{CO}$ = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

$PE_{VOC}$ = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

$PE_{PM10}$ = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb $PM_{10}$/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb $PM_{10}$/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb $PM_{10}$/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb $PM_{10}$/year**

$PE_{SOx}$ = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb $SO_X$/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb $SO_X$/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb $SO_X$/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb $SO_X$/year**

| **Post Project Potential to Emit (PE2) (C-3953-14-1)** | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $NO_X$ | 1.90 | 45.5 | 24 | 95 |
| CO | 1.14 | 27.3 | 14 | 57 |
| VOC | 0.63 | 15.0 | 8 | 31 |
| $PM_{10}$ | 0.06 | 1.5 | 1 | 3 |
| $SO_X$ | 0.02 | 0.4 | 0 | 1 |

### 3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

### 4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

| Post-project Stationary Source Potential to Emit [SSPE2] (lb/year) | | | | | | | |
|---|---|---|---|---|---|---|---|
| Permit Unit | $NO_X$ * | CO ** | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ | $PM_{2.5}$ *** |
| C-3953-10-1 | 198,840 | 197,928 | 34,489 | 80,656 | 16,694 | 219,972 | 80,656 |
| C-3953-11-1 | | | 34,489 | 80,656 | 16,694 | 219,972 | 80,656 |
| C-3953-12-1 | | | 201 | 233 | 132 | 0 | 233 |
| C-3953-13-1 | | | 12 | 2 | 0 | 0 | 2 |
| C-3953-14-1 | | | 31 | 3 | 1 | 0 | 3 |
| Post-project SSPE (SSPE2) | **198,840** | **197,928** | **69,222** | **161,550** | **33,521** | **439,944** | **161,550** |

* The facility has proposed to limit the $NO_X$ emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All $PM_{10}$ emissions are $PM_{2.5}$.

## 5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

| Major Source Determination | | | | | | |
|---|---|---|---|---|---|---|
| | $NO_X$ (lb/year) | CO (lb/year) | VOC (lb/year) | $PM_{10}$ (lb/year) | $SO_X$ (lb/year) | $PM_{2.5}$ (lb/year) |
| Post-project SSPE (SSPE2) | 198,840 | 197,928 | 69,222 | 161,550 | 33,521 | 161,550 |
| Major Source Threshold | 50,000 | 200,000 | 50,000 | 140,000 | 140,000 | 200,000 |
| Major Source? | Yes | No | Yes | Yes | No | No |

## 6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for $NO_X$, VOC, and $PM_{10}$ emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline $NO_X$, CO, VOC, $PM_{10}$ and $SO_X$ emissions will be set equal to the following:

BE = 0 lb/year

### 7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

### 8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

## VIII. COMPLIANCE:

***Rule 1080 Stack Monitoring***

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

The two CTGs will be equipped with operational CEMs for $NO_X$, CO, and $O_2$. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

***Proposed Rule 1080 Conditions:***

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas $NO_X$, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The $NO_X$, CO and $O_2$ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for $NO_X$, CO and $O_2$ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for $NO_X$ emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

**ii. C-3953-12-1 (Boiler)**

The boiler will be equipped with operational CEMs for $NO_X$, CO, and $O_2$. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

***Proposed Rule 1080 Conditions:***

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

***Rule 1081 Source Sampling***

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

***Proposed Rule 1081 Conditions:***

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: $NO_X$ - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

**ii. C-3953-12-1 (Boiler)**

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

***Proposed Rule 1081 Conditions:***

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

***Rule 1100 Equipment Breakdown***

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

***Proposed Rule 1100 Conditions:***

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

***Rule 2010 Permits Required***

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of a DOC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

***Rule 2201 New and Modified Stationary Source Review Rule***

***A. BACT:***

**1. BACT Applicability**

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$. BACT is triggered for $NO_X$, VOC, $PM_{10}$, and $SO_X$ criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for $NO_X$. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

**ii. C-3953-12-1 (Boiler)**

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$. BACT is triggered for $NO_X$, VOC, and $PM_{10}$ criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for $NO_X$, CO, and VOC. BACT is triggered for $NO_X$, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

**iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)**

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for $NO_X$, CO, and VOC. BACT is triggered for $NO_X$, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

**2. BACT Guidance**

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

**ii. C-3953-12-1 (Boiler)**

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

**iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)**

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

**3. Top-Down Best Available Control Technology (BACT) Analysis**

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

**4. BACT Summary:**

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

BACT has been satisfied by the following:

$NO_X$: 2.0 ppmv @ 15% $O_2$ (1-hour rolling average, except during startup/shutdown) with Dry Low $NO_X$ Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% $O_2$ (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% $O_2$ (with duct burner firing; 3-hr rolling average).

$PM_{10}$: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

$SO_X$: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

**ii. C-3953-12-1 (Boiler)**

BACT has been satisfied by the following:

$NO_X$: 9.0 ppmv @ 15% $O_2$ with Ultra Low $NO_X$ burners and natural gas fuel.

VOC: Natural gas fuel.

$PM_{10}$: Natural gas fuel.

$SO_X$: Natural gas fuel.

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

BACT has been satisfied by the following:

$NO_X$: Certified $NO_X$ emissions of 6.9 g/hp·hr or less

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

**iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)**

BACT has been satisfied by the following:

$NO_X$: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

## _C. Offsets:_

### 1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for $NO_X$ and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for $SO_X$ and 29,200 lbs/year for $PM_{10}$. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$ emissions. Therefore, offset calculations are necessary.

| Offset Determination | | | | | |
|---|---|---|---|---|---|
| | $NO_X$ (lb/year) | CO (lb/year) | VOC (lb/year) | $PM_{10}$ (lb/year) | $SO_X$ (lb/year) |
| Post-project SSPE (SSPE2) | 198,840 | 197,928 | 69,222 | 161,550 | 33,521 |
| Offset Threshold | 20,000 | 200,000 | 20,000 | 29,200 | 54,750 |
| Offsets Required? | Yes | No | Yes | Yes | No |

## 2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for $NO_X$, VOC, and $PM_{10}$ is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-1 and C-3953-14-1 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

**<u>$NO_X$ Offset Calculations:</u>**

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their $NO_X$ and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year * DOR

Quarterly Offsets $_{1st\ Qtr}$ = 67,103.75 lbs of $NO_X$ * DOR
Quarterly Offsets $_{2nd\ Qtr}$ = 67,103.75 lbs of $NO_X$ * DOR
Quarterly Offsets $_{3rd\ Qtr}$ = 67,103.75 lbs of $NO_X$ * DOR
Quarterly Offsets $_{4th\ Qtr}$ = 67,103.75 lbs of $NO_X$ * DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of $NO_X$ ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-$NO_X$/year x 1.5
Offsets Required = 402,623 lb-$NO_X$/year

Calculating the appropriate quarterly emissions to be offset is as follows:

| Quantity of Offsets Required | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | Total (lb/year) |
| $NO_X$ | 100,655 | 100,656 | 100,656 | 100,656 | 402,623 |

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in $NO_X$ emissions associated with this project. The above Certificates have available quarterly $NO_X$ credits as follows:

| Offset Proposal | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | **Total (lb/year)** |
| ERC #C-899-2 | 2,243 | 2,243 | 2,243 | 2,243 | **8,972** |
| ERC #C-902-2 | 13,879 | 6,131 | 1,086 | 8,539 | **29,635** |
| ERC #N-720-2 | 0 | 9 | 1,255 | 437 | **1,701** |
| ERC #N-722-2 | 0 | 1,166 | 88,317 | 1,422 | **90,905** |
| ERC #N-726-2 | 0 | 0 | 4,728 | 0 | **4,728** |
| ERC #N-728-2 | 10,542 | 3,731 | 2,487 | 5,171 | **21,931** |
| ERC #S-2814-2 | 6,121 | 13,869 | 18,914 | 11,461 | **50,365** |
| ERC #S-2321-2* | 51,000 | 51,000 | 51,000 | 51,000 | **204,000** |
| **Total** | **83,784** | **78,147** | **170,027** | **80,269** | **412,227** |

*ERC certificate split from this ERC.

Project $NO_X$ offset requirements

The applicant states that $NO_X$ ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the $NO_X$ offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in $NO_X$ or VOC during any period of the year. Since 3rd quarter $NO_X$ ERCs will be used to offset $NO_X$ emissions, the above applies to the $NO_X$ ERCs.

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| $NO_X$ Emissions to be offset: (at a 1.5:1 DOR): | 100,655 | 100,656 | 100,656 | 100,656 |
| Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*: | 83,784 | 78,147 | 170,027 | 80,269 |
| 3rd qtr. ERCs applied to 1st qtr. ERCs: | 16,871 | 0 | -16,871 | 0 |
| 3rd qtr. ERCs applied to 2nd qtr. ERCs: | 0 | 22,509 | -22,509 | 0 |
| 3rd qtr. ERCs applied to 4th qtr. ERCs: | 0 | 0 | -20,387 | 20,387 |
| Remaining ERCs from certificates S-2321-2: | 0 | 0 | 9,604 | 0 |
| Remaining $NO_X$ emissions to be offset (at a 1.5:1 DOR): | 0 | 0 | 0 | 0 |

As seen above, the facility has sufficient credits to fully offset the quarterly $NO_X$ emissions increases associated with this project.

**VOC Offset Calculations:**

VOC SSPE2 = 69,222 lb/year
C-3953-13-1 (VOC) = 12 lb/year
C-3953-14-1 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

| Quantity of Offsets Required | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | Total (lb/year) |
| VOC | 18,442 | 18,442 | 18,442 | 18,442 | 73,769 |

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

| Offset Proposal | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | **Total (lb/year)** |
| ERC #C-897-1 | 45 | 45 | 45 | 45 | **180** |
| ERC #C-898-1 | 5,480 | 6,496 | 4,696 | 6,616 | **23,288** |
| ERC #N-724-1 | 0 | 0 | 241 | 0 | **241** |
| ERC #N-725-1 | 0 | 0 | 709 | 0 | **709** |
| ERC #S-2812-1 | 31,432 | 31,424 | 31,417 | 31,417 | **125,690** |
| ERC #S-2813-1 | 12,500 | 12,500 | 12,500 | 12,500 | **50,000** |
| ERC #S-2817-1 | 11,431 | 11,424 | 11,417 | 11,417 | **45,689** |
| **Total** | **60,887** | **61,887** | **61,022** | **61,991** | **245,787** |

Project VOC offset requirements

The applicant states that $NO_X$ ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| VOC Emissions to be offset: (at a 1.5:1 DOR): | 18,442 | 18,442 | 18,442 | 18,442 |
| Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1, | 5,525 | 6,541 | 5,691 | 6,661 |
| Remaining VOC emissions to be offset (at a 1.5:1 DOR): | 12,917 | 11,901 | 12,751 | 11,781 |
| VOC Emissions to be offset: (at a 1.5:1 DOR): | 12,917 | 11,901 | 12,751 | 11,781 |
| Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1 | 55,363 | 55,348 | 55,334 | 55,334 |
| Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1: | 42,446 | 43,447 | 42,583 | 43,553 |
| Remaining VOC emissions to be offset (at a 1.5:1 DOR): | 0 | 0 | 0 | 0 |

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

**$PM_{10}$ Offset Calculations:**

$PM_{10}$ SSPE2 = 161,550 lb/year
C-3953-13-1 ($PM_{10}$) = 2 lb/year
C-3953-14-1 ($PM_{10}$) = 3 lb/year
$PM_{10}$ Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of $PM_{10}$ ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of $PM_{10}$ ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of $PM_{10}$ ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of $PM_{10}$ ∗ DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of $PM_{10}$ ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

| **Quantity of Offsets Required** | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | Total (lb/year) |
| $PM_{10}$ | 49,630 | 49,629 | 49,629 | 49,630 | 198,518 |

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in $PM_{10}$ emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

| **Offset Proposal** | | | | | |
|---|---|---|---|---|---|
| | 1st Quarter (lb/qtr) | 2nd Quarter (lb/qtr) | 3rd Quarter (lb/qtr) | 4th Quarter (lb/qtr) | **Total (lb/year)** |
| ERC #C-896-4 | 80 | 80 | 80 | 80 | **320** |
| ERC #N-721-4 | 0 | 0 | 3,215 | 0 | **3,215** |
| ERC #N-723-4 | 0 | 0 | 985 | 0 | **985** |
| ERC #S-2791-5 | 92,179 | 23,666 | 69,157 | 96,288 | **281,290** |
| ERC #S-2790-5 | 12,862 | 491 | 0 | 8,499 | **21,852** |
| ERC #S-2789-5 | 6 | 14 | 12 | 8 | **40** |
| ERC #S-2788-5 | 5 | 7 | 3 | 6 | **21** |
| ERC #N-762-5 | 21,000 | 21,000 | 21,000 | 21,000 | **84,000** |
| **Total** | **126,131** | **45,256** | **94,449** | **125,877** | **391,723** |

Project $PM_{10}$ offset requirements

The applicant states either $PM_{10}$ ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the $PM_{10}$ offset requirements.

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| $PM_{10}$ Emissions to be offset: (at a 1.5:1 ratio): | 49,630 | 49,629 | 49,629 | 49,630 |
| Available ERCs from certificates C-896-4, N-721-4, and N-723-4: | 80 | 80 | 4,280 | 80 |
| ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4: | -80 | -80 | -4,280 | -80 |
| Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4: | 0 | 0 | 0 | 0 |
| Remaining $PM_{10}$ emissions to be offset (at a 1.5:1 ratio): | 49,550 | 49,549 | 45,349 | 49,550 |

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between $PM_{10}$ and $PM_{10}$ precursors (i.e. $SO_X$) may be allowed. The applicant is proposing to use interpollutant offsets $SO_X$ for $PM_{10}$ at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the $SO_X$ ERCs are being used to offset $PM_{10}$ emissions, the above applies to the $SO_X$ ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| Remaining $PM_{10}$ Emissions to be offset: (at a 1.5:1 ratio): | 49,550 | 49,549 | 45,349 | 49,550 |
| Remaining $PM_{10}$ emissions to be offset with $SO_X$ ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 49,550 | 49,549 | 45,349 | 49,550 |
| Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5: | 33,873 | 21,512 | 21,015 | 29,513 |
| Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5: | 0 | 0 | 0 | 0 |
| Remaining $PM_{10}$ emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |

| | 1[st] Quarter | 2[nd] Quarter | 3[rd] Quarter | 4[th] Quarter |
|---|---|---|---|---|
| Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |
| Remaining ERCs from certificate S-2791-5: | 92,179 | 23,666 | 69,157 | 96,288 |
| 1[st] qtr. ERCs applied to 2[nd] qtr. ERCs: | -4,371 | 4,371 | 0 | 0 |
| Adjusted Remaining ERCs from certificate S-2791-5: | 87,808 | 28,037 | 69,157 | 96,288 |
| Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |
| ERCs applied from certificate S-2791-5 partially withdrawn: | 15,677 | 28,037 | 24,334 | 20,037 |
| Remaining ERCs from certificate S-2791-5: | 72,131 | 0 | 44,823 | 76,251 |

As seen above, the facility has sufficient credits to fully offset the quarterly $SO_X$ and $PM_{10}$ emissions increases associated with this project.

**<u>Offset Conditions:</u>**

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide $PM_{10}$ emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

## *D. Public Notification:*

### 1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

#### a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for $NO_X$, VOC, and $PM_{10}$. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

#### b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

#### c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

| Post-Project Potential to Emit | | | | | | |
|---|---|---|---|---|---|---|
| Permit Unit | $NO_X$ (lb/day) | CO (lb/day) | VOC (lb/day) | $PM_{10}$ (lb/day) | $SO_X$ (lb/day) | $NH_3$ (lb/day) |
| C-3953-10-1 | 789.6 | 5,590.8 | 202.0 | 282.7 | 159.6 | 771.1 |
| C-3953-11-1 | 789.6 | 5,590.8 | 202.0 | 282.7 | 159.6 | 771.1 |
| C-3953-12-1 | 4.9 | 16.6 | 1.9 | 2.2 | 1.3 | 0 |
| C-3953-13-1 | 51.8 | 6.8 | 5.8 | 0.9 | 0.1 | 0 |
| C-3953-14-1 | 45.5 | 27.3 | 15.0 | 1.5 | 0.4 | 0 |
| **Threshold (lb/day)** | **100** | **100** | **100** | **100** | **100** | **100** |
| Notification Required? | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** | **Yes** |

According to the table above, permit units C-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for $NO_X$, CO, VOC, $PM_{10}$, $SO_X$, or $NH_3$ emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

**e. Offset Threshold**

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

| Offset Threshold | | | | |
|---|---|---|---|---|
| Pollutant | SSPE1 (lb/year) | SSPE2 (lb/year) | Offset Threshold | Public Notice Required? |
| $NO_X$ | 0 | 198,840 | 20,000 lb/year | Yes |
| CO | 0 | 197,928 | 200,000 lb/year | No |
| VOC | 0 | 69,222 | 20,000 lb/year | Yes |
| $PM_{10}$ | 0 | 161,550 | 29,200 lb/year | Yes |
| $SO_X$ | 0 | 33,521 | 54,750 lb/year | No |

As detailed above, offset thresholds were surpassed for $NO_X$, VOC, and $PM_{10}$ emissions with this project; therefore public noticing is required for offset purposes.

**f. SSIPE Notification**

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary

Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

| SSIPE Notification | | | | | |
|---|---|---|---|---|---|
| **Pollutant** | **SSPE2 (lb/year)** | **SSPE1 (lb/year)** | **SSIPE (lb/year)** | **SSIPE Public Notice Threshold** | **Public Notice Required?** |
| $NO_X$ | 198,840 | 0 | 198,840 | 20,000 lb/year | Yes |
| CO | 197,928 | 0 | 197,928 | 20,000 lb/year | Yes |
| VOC | 69,222 | 0 | 69,222 | 20,000 lb/year | Yes |
| $PM_{10}$ | 161,550 | 0 | 161,550 | 20,000 lb/year | Yes |
| $SO_X$ | 33,521 | 0 | 33,521 | 20,000 lb/year | Yes |

As demonstrated above, the SSIPE's for $NO_X$, CO, VOC, $PM_{10}$ and $SO_X$ emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

**2. Public Notice Requirements**

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

## ***E. Daily Emission Limits:***

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity.

***Proposed Rule 2201 (DEL) Conditions:***

The following condition will be included to demonstrate compliance with facility wide annual $NO_X$ and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

For the turbines, the DELs for $NO_X$, CO, VOC, $PM_{10}$, $SO_X$, and $NH_3$ will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; $PM_{10}$ – 11.78 lb/hr; $SO_X$ (as $SO_2$) – 6.652 lb/hr; or $NH_3$ – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: $NO_X$ (as $NO_2$) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; $PM_{10}$ – 282.7 lb/day; $SO_X$ (as $SO_2$) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; $PM_{10}$ – 80,656 lb/year; or $SO_X$ (as $SO_2$) – 16,694 lb/year; or $NH_3$ – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

**ii. C-3953-12-1 (Boiler)**

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

**iii. C-3953-13-1 (Diesel IC engine fire pump)**

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

**iv. C-3953-14-1 (Natural gas IC engine electrical generator)**

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

## *F. Compliance Certification:*

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

## *G. Air Quality Impact Analysis:*

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for $NO_X$, CO, and $SO_X$. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for $NO_X$, CO, or $SO_X$.

| AAQA Results Summary | | | | | |
|---|---|---|---|---|---|
| Pollutant | 1 hr Average | 3 hr Average | 8 hr Average | 24 hr Average | Annual Average |
| CO | Pass | N/A | Pass | N/A | N/A |
| $NO_x$ | Pass | N/A | N/A | N/A | Pass |
| $SO_x$ | Pass | Pass | N/A | Pass | Pass |

The proposed location is in a non-attainment area for $PM_{10}$. The increase in the ambient $PM_{10}$ concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

| Significance Levels | | | | | |
|---|---|---|---|---|---|
| Pollutant | Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2) | | | | |
| | Annual Avg. | 24 hr Avg. | 8 hr Avg. | 3 hr Avg. | 1 hr Avg. |
| $PM_{10}$ | 1.0 | 5 | N/A | N/A | N/A |

| Calculated Contribution | | | | | |
|---|---|---|---|---|---|
| Pollutant | Calculated Contributions ($\mu g/m^3$) | | | | |
| | Annual Avg. | 24 hr Avg. | 8 hr Avg. | 3 hr Avg. | 1 hr Avg. |
| $PM_{10}$ | 0.38 | 1.6 | N/A | N/A | N/A |

As shown, the calculated contribution of $PM_{10}$ will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

## *H. Compliance Assurance:*

### 1. Source Testing

#### i. C-3953-10-1 and C-3953-11-1

District Rule 4703 requires $NO_X$ and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and $PM_{10}$ emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for $NO_X$, CO, VOC, $PM_{10}$, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of $NO_X$, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for $NO_X$, CO, and $O_2$. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of $NO_X$ and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires $NO_X$ testing for the duct burners. The District will accept the $NO_X$ source testing required by District Rule 4703 as equivalent to $NO_X$ testing required by 40 CFR 60 subpart Db.

**ii. C-3953-12-1**

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

**iii. C-3953-13-1 and C-3953-14-1**

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

**2. Monitoring**

**i. C-3953-10-1 and C-3953-11-1**

Monitoring of $NO_X$ emissions is required by District Rule 4703. The applicant has proposed a CEMS for $NO_X$.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

**ii. C-3953-12-1**

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

**iii. C-3953-13-1 and C-3953-14-1**

No monitoring is required to demonstrate compliance with Rule 2201.

**3. Recordkeeping**

**i. C-3953-10-1 and C-3953-11-1**

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

**ii. C-3953-12-1**

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

**iii. C-3953-13-1 and C-3953-14-1**

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

**4. Reporting**

**i. C-3953-10-1 and C-3953-11-1**

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the $NO_X$ emission limit of the permit. Such reporting will be required.

**ii. C-3953-12-1**

No reporting is required to demonstrate compliance with Rule 2201.

**iii. C-3953-13-1 and C-3953-14-1**

No reporting is required to demonstrate compliance with Rule 2201.

***Rule 2520 Federally Mandated Operating Permits***

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for $NO_X$, VOC, and $PM_{10}$ after this project.
- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.
- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.
- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is not required to obtain a PSD permit.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

***Rule 2540 Acid Rain Program***

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the $NO_X$ and $SO_X$ emissions and a relatively small quantity of $SO_X$ allowances (from a national $SO_X$ allowance bank) will be required as well as the use of a $NO_X$ CEM.

The following condition will be placed on permits C-3953-10-1, -11-1 and -14-1 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

### *Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics*

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[8] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low $NO_X$ combustor-equipped large frame turbine.

[7] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).
[8] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

**Hazardous Air Pollutant Emissions (per CATEF)**
**Avenal Energy Project – GE Frame 7 (with Duct Burners)**

| Hazardous Air Pollutant | CATEF Emission Factor (lb/MMSCF)(1) | Maximum Hourly Emissions per Turbine (lb/hr) (2) | Maximum Annual Emissions per Turbine (tpy) (3) | Maximum Annual Emissions both Turbines (tpy) |
|---|---|---|---|---|
| Acetaldehyde | 4.08E-02 | 0.09 | 0.33 | 0.67 |
| Acrolein | 3.69E-03 | 0.01 | 0.03 | 6.04E-02 |
| Benzene | 3.33E-03 | 0.01 | 0.03 | 5.45E-02 |
| 1,3-Butadiene | 4.39E-04 | 9.38E-04 | 3.59E-03 | 7.19E-03 |
| Ethyl benzene | 3.26E-02 | 0.07 | 0.27 | 0.53 |
| Formaldehyde | 1.65E-01 | 0.35 | 1.35 | 2.70 |
| Hexane | 2.59E-01 | 0.55 | 2.12 | 4.24 |
| Naphthalene | 1.33E-03 | 2.84E-03 | 1.09E-02 | 2.18E-02 |
| Polycyclic aromatic hydrocarbons (PAH) | --- | --- | --- | --- |
| Anthracene | 3.38E-05 | 7.22E-05 | 2.77E-04 | 5.53E-04 |
| Benzo(a)anthracene | 2.26E-05 | 4.83E-05 | 1.85E-04 | 3.70E-04 |
| Benzo(a)pyrene | 1.39E-05 | 2.97E-05 | 1.14E-04 | 2.28E-04 |
| Benzo(b)fluoranthrene | 1.13E-05 | 2.41E-05 | 9.25E-05 | 1.85E-04 |
| Benzo(k)fluoranthrene | 1.10E-05 | 2.35E-05 | 9.00E-05 | 1.80E-04 |
| Chrysene | 2.52E-05 | 5.38E-05 | 2.06E-04 | 4.12E-04 |
| Dibenz(a,h)anthracene | 2.35E-05 | 5.02E-05 | 1.92E-04 | 3.85E-04 |
| Indeno(1,2,3-cc)pyrene | 2.35E-05 | 5.02E-05 | 1.92E-04 | 3.85E-04 |
| Propylene oxide | 2.96E-02 | 6.32E-02 | 2.42E-01 | 0.48 |
| Toluene | 1.33E-01 | 0.28 | 1.09 | 2.18 |
| Xylenes | 6.53E-02 | 0.14 | 0.53 | 1.07 |
| **Total** | | | **6.01** | **12.02** |

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)
(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

***Rule 4001 New Source Performance Standards***

**40 CFR 60 – Subpart Dc**

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for $SO_X$ and $PM_{10}$.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

*The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.*

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

*This requirement is not applicable since the units are not subject to §60.42c or §40.43c.*

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

*The facility has not proposed an annual capacity factor; therefore one will not be required.*

(4) Notification if an emerging technology will be used for controlling $SO_2$ emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

*This requirement is not applicable since the units will not be equipped with an emerging technology used to control $SO_2$ emissions.*

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]
- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

**<u>40 CFR 60 – Subpart GG</u>**

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

**<u>40 CFR 60 - Subpart IIII</u>**

<u>§60.4200 - Applicability</u>

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

## 40 CFR Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

| | Table 1 Limit | Proposed Emissions | Compliant |
|---|---|---|---|
| NOx (g/bhp-hr) | 2.0 | 1.0 | Yes |
| CO (g/bhp-hr) | 4.0 | 0.6 | Yes |
| VOC (g/bhp-hr) | 1.0 | 0.33 | Yes |

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

## 40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide ($NO_X$) and sulfur dioxide ($SO_X$) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that $NO_X$ emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for $NO_X$. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a $NO_X$ emissions limit of 15 ppmvd @ 15% $O_2$ or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a $NO_X$ emission concentration limit of 2.0 ppmvd @ 15% $O_2$ for each turbine. Therefore, the proposed turbines will be operating in compliance with the $NO_X$ emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain $SO_2$ in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the $SO_X$ emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – $NO_X$ Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce $NO_X$ emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – $NO_X$ Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas $NO_X$, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each $NO_X$ diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a $NO_X$ diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the $NO_X$ monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the $NO_X$ emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a $NO_X$ CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The $NO_X$, CO and $O_2$ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

Section 60.4350 – CEMS Data and Excess $NO_X$ Emissions:

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both $NO_X$ and diluent monitors, the data acquisition and handling system must calculate and record the hourly $NO_X$ emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$ (or the hourly average $CO_2$ concentration is less than 1.0 percent $CO_2$), a diluent cap value of 19.0 percent $O_2$ or 1.0 percent $CO_2$ (as applicable) may be used in the emission calculations.

(c) Correction of measured $NO_X$ concentrations to 15 percent $O_2$ is not allowed.

(d) If you have installed and certified a $NO_X$ diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average $NO_X$ emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the $NO_X$ emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess $NO_X$ emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for $NO_X$ emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure $NO_X$ emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for units located in continental areas and 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng $SO_2$/J (0.060 lb $SO_2$/MMBtu) heat input for continental areas or 180 ng $SO_2$/J (0.42 lb $SO_2$/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess $NO_X$ Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the $NO_X$ emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average $NO_X$ emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average $NO_X$ emission rate" is the arithmetic average of the average $NO_X$ emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average $NO_X$ emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid $NO_X$ emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average $NO_X$ emission rate" is the arithmetic average of all hourly $NO_X$ emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly $NO_X$ emissions rates for the preceding 30 unit operating days if a valid $NO_X$ emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: $NO_X$ concentration, CO2 or $O_2$ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the $NO_X$ emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the $NO_X$ emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average $NO_X$ concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either $NO_X$ or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess $SO_X$ Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess $SO_X$ emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess $NO_X$ emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – $NO_X$ Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent $NO_X$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% $O_2$), NH3 emission rate (ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: $NO_X$ - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a $NO_X$-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of $NO_X$ emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the $NO_X$ emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– $SO_X$ Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent $SO_2$ performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the $SO_2$ concentration in the exhaust stream. Avenal Power Center is not proposing to measure the $SO_2$ in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

***Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)***

**40 CFR 63 Subpart ZZZZ**

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, "A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site."

§6585(c) states, "An area source of HAP emissions is a source that is not a major source."

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

> (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.
>
> (ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.
>
> (iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

> (i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.
>
> (ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

***Rule 4101 Visible Emissions***

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**ii. C-3953-12-1 (Boiler)**

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the DOC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**iii. C-3953-13-1 (Diesel IC engine powering fire water pump)**

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

**iv. C-3953-14-1 (Natural gas IC engine electrical generator)**

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

***Rule 4102 Nuisance***

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

**A. California Health & Safety Code 41700 (Health Risk Analysis)**

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

| Screen HRA Summary | | | | |
|---|---|---|---|---|
| | Acute Hazard Index | Chronic Hazard Index | 70 yr Cancer Risk | T-BACT Required? |
| C-3953-10-1 (Turbine #1) | 0.0 | 0.0 | 0.02 | No |
| C-3953-11-1 (Turbine #2) | 0.0 | 0.0 | 0.02 | No |
| C-3953-12-1 (Auxiliary Boiler) | 0.0 | 0.0 | 0.01 | No |
| C-3953-13-1 (Diesel-Fired IC Engine Fire Pump) | N/A* | N/A* | 0.01 | No |
| C-3953-14-1 (NG-Fired IC Engine Generator) | 0.2 | 0.0 | 0.0 | No |

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

**B. Discussion of Toxics BACT (TBACT)**

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

***Rule 4201 Particulate Matter Concentration***

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

**i. C-3953-10-1 and –11-1 (Turbines)**

*PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)*

$PM_{10}$ emission rate = 11.78 lb/hr. Assuming 100% of PM is $PM_{10}$
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) $*$ (7,000 gr/lb)] $\div$ [(1,071,653 $ft^3$/min) $*$ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**ii. C-3953-12-1 (Boiler)**

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor: 0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust: 100%
Exhaust Oxygen ($O_2$) Concentration: 3%

$$\text{Excess Air Correction to F Factor} = \frac{20.9}{(20.9 - 3)} = 1.17$$

$$GL = \left( \frac{0.005\ lb-PM}{MMBtu} \times \frac{7{,}000\ grain}{lb-PM} \right) / \left( \frac{8{,}578\ ft^3}{MMBtu} \times 1.17 \right)$$

$$GL = 0.0035\ grain/dscf < 0.1\ grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**iii. C-3953-13-1 (Diesel IC engine fire pump)**

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

**iv. C-3953-14-1 (Natural gas IC engine electrical generator)**

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.008\ \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

***Rule 4202 Particulate Matter Emission Rate***

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

**Rule 4301** ***Fuel Burning Equipment***

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

**i. C-3953-10-1 and C-3953-11-1 (Turbines)**

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

**ii. C-3953-12-1 (Boiler)**

| District Rule 4301 Limits | | | |
|---|---|---|---|
| Pollutant | $NO_2$ | Total PM | $SO_2$ |
| C-3953-12-1 (lb/hr) | 0.41 | 0.19 | 0.10 |
| Rule Limit (lb/hr) | 140 | 10 | 200 |

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

**iii. C-3953-13-1 (Diesel IC engine fire pump)**

Rule 4301 does not apply to the affected equipment and no further discussion is required.

**iv. C-3953-14-1 (Natural gas IC engine electrical generator)**

Rule 4301 does not apply to the affected equipment and no further discussion is required.

***Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters***

This rule is only applicable to unit C-3953-12-1.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

***Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2***

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

**Conclusion**

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

***Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3***

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

**Section 5.1, $NO_X$ and CO Emissions Limits**

Section 5.1.1 requires that except for units subject to Sections 5.2, $NO_X$ and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

| Rule 4306 Emissions Limits | | | | |
|---|---|---|---|---|
| Category | Operated on gaseous fuel | | Operated on liquid fuel | |
| | $NO_X$ Limit | CO Limit | $NO_X$ Limit | CO Limit |
| B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units | 9 ppmv or 0.011 lb/MMBtu | 400 ppmv | 40 ppmv or 0.052 lb/MMBtu | 400 ppmv |

For the unit:

- the proposed $NO_x$ emission factor is 9 ppmvd @ 3% $O_2$ (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% $O_2$ (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

**Section 5.2, Low Use**

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

**Section 5.3, Startup and Shutdown Provisions**

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low $NO_X$ burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

**Section 5.4, Monitoring Provisions**

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for $NO_X$, CO and $O_2$, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

**Section 5.5, Compliance Determination**

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable $NO_X$ analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

**Section 6.1, Recordkeeping**

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

**Section 6.2, Test Methods**

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

| Pollutant | Units | Test Method Required |
|---|---|---|
| $NO_X$ | ppmv | EPA Method 7E or ARB Method 100 |
| $NO_X$ | lb/MMBtu | EPA Method 19 |
| CO | ppmv | EPA Method 10 or ARB Method 100 |
| Stack Gas $O_2$ | % | EPA Method 3 or 3A, or ARB Method 100 |
| Stack Gas Velocities | ft/min | EPA Method 2 |
| Stack Gas Moisture Content | % | EPA Method 4 |

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} $NO_X$ emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen ($O_2$) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

**Section 6.3, Compliance Testing**

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

**Section 6.4, Emission Control Plan (ECP)**

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

**Section 7.0, Compliance Schedule**

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

**Conclusion**

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

***Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1***

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at $NO_x$ Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

***Rule 4701 Internal Combustion Engines – Phase 1***

This rule is only applicable to units C-3953-13-1 and –14-1.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

***Rule 4702 Internal Combustion Engines – Phase 2***

This rule is only applicable to units C-3953-13-1 and –14-1.

The purpose of this rule is to limit the emissions of nitrogen oxides ($NO_X$), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-1, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-1, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

**C-3953-14-1 (Natural Gas IC engine electrical generator)**

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the DOC to ensure compliance:

**C-3953-13-1 (Diesel IC engine fire pump)**

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

**C-3953-14-1 (Natural Gas IC engine electrical generator)**

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

***Rule 4703 Stationary Gas Turbines***

This rule is only applicable to units C-3953-10-1 and -11-1.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – $NO_X$ Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the $NO_X$ emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the $NO_X$ emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% $O_2$ (Standard option) and 3 ppmv @ 15% $O_2$ (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% $O_2$ (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% $O_2$. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% $O_2$ and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;

- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

A description of what physical conditions prevail during the period that prevent the controls from being effective; and

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to $N_2$. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufactúrer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; $PM_{10}$ – 11.78 lb/hr; $SO_X$ (as $SO_2$) – 6.652 lb/hr; or $NH_3$ – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for $NO_X$ and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the $NO_X$ and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas $NO_X$, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas $NO_X$ control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control $NO_X$ emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas $NO_X$ emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure $NO_X$ output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for $NO_X$ available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the $NO_X$ control system operating parameters to the associated measured $NO_X$ output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the $NO_X$ control system operating parameters to the associated measured $NO_X$ output. The information must be sufficient to allow the District to determine compliance with the $NO_X$ emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas $NO_X$ and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas $NO_X$ and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% $O_2$), NH3 emission rate (ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the $NO_X$ and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the $NO_X$ and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: $NO_X$ - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

***Rule 4801 Sulfur Compounds***

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as $SO_2$ on a dry basis averaged over 15 consecutive minutes:

**i. C-3953-10-1 and –11-1 (Turbines)**

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the $SO_X$ exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of $SO_X$: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of $SO_X$ produced per MMBtu of fuel.
- Weight of $SO_X$ as $SO_2$ is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \dfrac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of $SO_X$ per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of $SO_X$ volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

**ii. C-3953-12-1 (Boiler)**

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume $SO_2$ = $\dfrac{n\ RT}{P}$

With:

N = moles $SO_2$
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\dfrac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.00282\, lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\, psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97 \frac{parts}{million}$$

$$SulfurConcentration = 1.97\frac{parts}{million}$$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

**iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)**

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume $SO_2$ = (n x R x T) ÷ P
n = moles $SO_2$
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$\frac{0.000015\,lb-S}{lb-fuel}\times\frac{7.1\,\text{lb}}{\text{gal}}\times\frac{64\,\text{lb}-\text{SO}_2}{32\,\text{lb}-\text{S}}\times\frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}}\times\frac{1\,\text{gal}}{0.137\,\text{MMBtu}}\times\frac{\text{lb}-\text{mol}}{64\,\text{lb}-\text{SO}_2}\times\frac{10.73\,\text{psi}-\text{ft}^3}{\text{lb}-\text{mol}-{}^\circ\text{R}}\times\frac{520^\circ\text{R}}{14.7\,\text{psi}}\times 1{,}000{,}000 = 1.0\ \text{ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

**iv. C-3953-14-1 (Natural gas IC engine powering an electrical generator)**

Volume $SO_2$ = (n x R x T) ÷ P
n = moles $SO_2$
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$2.85\ \frac{lb-S}{MMscf-gas}\times\frac{1\,scf-gas}{1{,}000\,Btu}\times\frac{1\,MMBtu}{8{,}578\,scf}\times\frac{1\,lb-mol}{64\,lb-S}\times\frac{10.73\,psi-ft^3}{lb-mol-{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times 1{,}000{,}000 = 1.97\ \text{ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

| | |
|---|---|
| ***District Rule 8011*** | ***General Requirements*** |
| ***District Rule 8021*** | ***Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities*** |
| ***District Rule 8031*** | ***Bulk Materials*** |
| ***District Rule 8041*** | ***Carryout And Trackout*** |
| ***District Rule 8051*** | ***Open Areas*** |
| ***District Rule 8061*** | ***Paved And Unpaved Roads*** |
| ***District Rule 8071*** | ***Unpaved Vehicle/Equipment Traffic Areas*** |
| ***District Rule 8081*** | ***Agricultural Sources*** |

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

**California Environmental Quality Act (CEQA)**

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

**California Health & Safety Code, Section 42301.6 (School Notice)**

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

**California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")**

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

**Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)**

The requirements of this section are only applicable to C-3953-13-1.

Particulate Matter and VOC + $NO_X$, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + $NO_X$, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for $NO_X$ + VOC and PM emissions).

| Requirements of Title 13 CCR, Section 2423 | | | | | | | |
|---|---|---|---|---|---|---|---|
| Source | Maximum Rated Power | Model Year | $NO_X$ | VOC | $NO_X$ + VOC | CO | PM |
| Title 13 CCR, §2423 | 174.3 – 301.6 bhp (130 - 225 kW) | 1996-2002 (Tier 1) | 6.9 g/bhp-hr (9.2 g/kW-hr) | 1.0 g/bhp-hr (1.3 g/kW-hr) | -- | 8.5 g/bhp-hr (11.4 g/kW-hr) | 0.40 g/bhp-hr (0.54 g/kW-hr) |
| **Title 13 CCR, §2423** | **174.3 – 301.6 bhp (130 - 225 kW)** | **2003-2005, extended to 2008 (Tier 2)** | -- | -- | **4.9 g/bhp-hr (6.6 g/kW-hr)** | **2.6 g/bhp-hr (3.5 g/kW-hr)** | **0.15 g/bhp-hr (0.20 g/kW-hr)** |
| Title 13 CCR, §2423 | 174.3 – 301.6 bhp (130 - 225 kW) | 2006 and later, extended to 2009 (Tier 3) | -- | -- | 3.0 g/bhp-hr (4.0 g/kW-hr) | 2.6 g/bhp-hr (3.5 g/kW-hr) | 0.15 g/bhp-hr (0.20 g/kW-hr) |
| Cummins, Model #CFP83-F40 | 288 bhp | 2007 | -- | -- | 3.8g/bhp-hr (5.1 g/kW-hr) | 0.447 g/bhp-hr (0.60 g/kW-hr) | 0.059 g/bhp-hr (0.079 g/kW-hr) |
| | | Meets Standard? | N/A | N/A | Yes | Yes | Yes |

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a $NO_X$ emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a $NO_X$ + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a $PM_{10}$ emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards:</u>

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, $NO_X$ + VOC, VOC, $NO_X$, and CO emission rate standards; and

2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

**Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines**

The requirements of this section are only applicable to C-3953-13-1.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a $PM_{10}$ emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

   I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
   II. Amount of fuel purchased;
   III. Date when the fuel was purchased;
   IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
   V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

## IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

## X. BILLING INFORMATION:

| **Annual Permit Fees** | | | |
|---|---|---|---|
| Permit Number | Fee Schedule | Fee Description | Annual Fee |
| C-3953-10-1 | 3020-08B-B | 180,000 kW | $12,229.00 |
| C-3953-11-1 | 3020-08B-B | 180,000 kW | $12,229.00 |
| C-3953-12-1 | 3020-02-H | 37.4 MMBtu/hr boiler | $953.00 |
| C-3953-13-1 | 3020-10-C | 288 bhp IC engine | $222.00 |
| C-3953-14-1 | 3020-10-E | 860 bhp IC engine | $557.00 |

# ATTACHMENT A

## *FDOC CONDITIONS*

**EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:**
**180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11**

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide $PM_{10}$ emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas $NO_X$, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The $NO_X$, CO and $O_2$ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for $NO_X$, CO and $O_2$ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for $NO_X$ emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated

emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; $PM_{10}$ – 11.78 lb/hr; $SO_X$ (as $SO_2$) – 6.652 lb/hr; or $NH_3$ – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: $NO_X$ (as $NO_2$) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; $PM_{10}$ – 282.7 lb/day; $SO_X$ (as $SO_2$) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; $PM_{10}$ – 80,656 lb/year; or $SO_X$ (as $SO_2$) – 16,694 lb/year; or $NH_3$ – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from

the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance

with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% $O_2$), NH3 emission rate (ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the $NO_X$ and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: $NO_X$ - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average $NO_X$ concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either $NO_X$ or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the $NO_X$ control system operating parameters to the associated measured $NO_X$ output. The information must be sufficient to allow the District to determine compliance with the $NO_X$ emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

58. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

59. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

60. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

61. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

62. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

63. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

64. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

65. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

67. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

**EQUIPMENT DESCRIPTION, UNIT C-3953-11-1:**
**180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10**

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide $PM_{10}$ emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas $NO_X$, CO and $O_2$ concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The $NO_X$, CO and $O_2$ CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for $NO_X$, CO and $O_2$ as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality

assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for $NO_X$ emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; $PM_{10}$ – 11.78 lb/hr; $SO_X$ (as $SO_2$) – 6.652 lb/hr; or $NH_3$ – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: $NO_X$ (as $NO_2$) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; $PM_{10}$ – 282.7 lb/day; $SO_X$ (as $SO_2$) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or $NH_3$ – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; $PM_{10}$ – 80,656 lb/year; or $SO_X$ (as $SO_2$) – 16,694 lb/year; or $NH_3$ – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with

the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% $O_2$), NH3 emission rate (ppmvd @ 15% $O_2$) and $PM_{10}$ emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the $NO_X$ and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: $NO_X$ - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and $O_2$ - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average $NO_X$ concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either $NO_X$ or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the $NO_X$ control system operating parameters to the associated measured $NO_X$ output. The information must be sufficient to allow the District to determine compliance with the $NO_X$ emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

**EQUIPMENT DESCRIPTION, UNIT C-3953-12-1:**
**37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER**

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide $PM_{10}$ emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this DOC. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the DOC. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

14. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

18. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

19. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

22. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

29. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

**EQUIPMENT DESCRIPTION, UNIT C-3953-13-1:**
**288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP**

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

8. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

11. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

**EQUIPMENT DESCRIPTION, UNIT C-3953-14-1:**
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: $NO_X$ (as $NO_2$) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

11. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

13. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

14. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

16. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

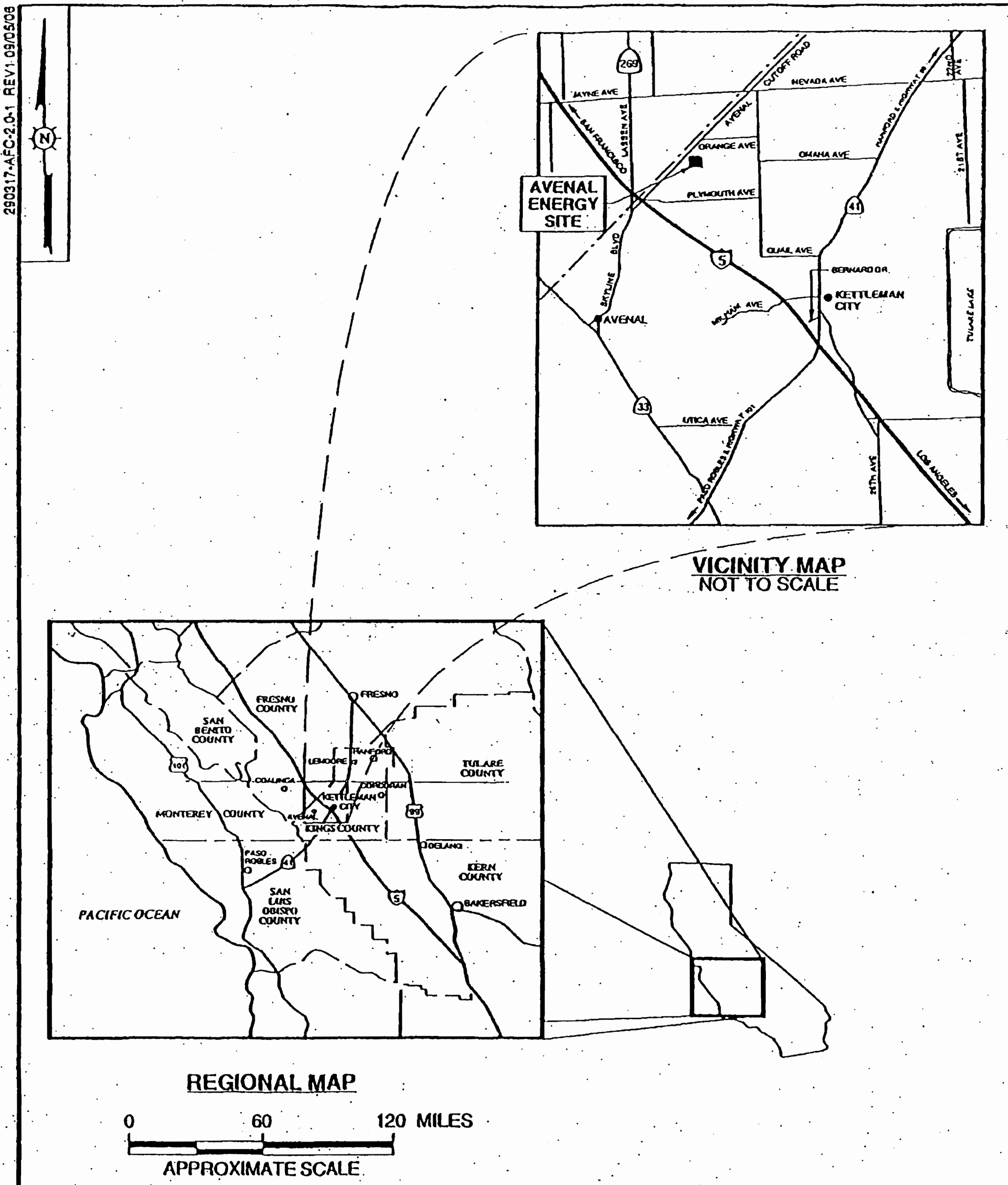
17. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

# ATTACHMENT B

***Project Location and Site Plan***

# ATTACHMENT C

## *CTG Commissioning Period Emissions Data*

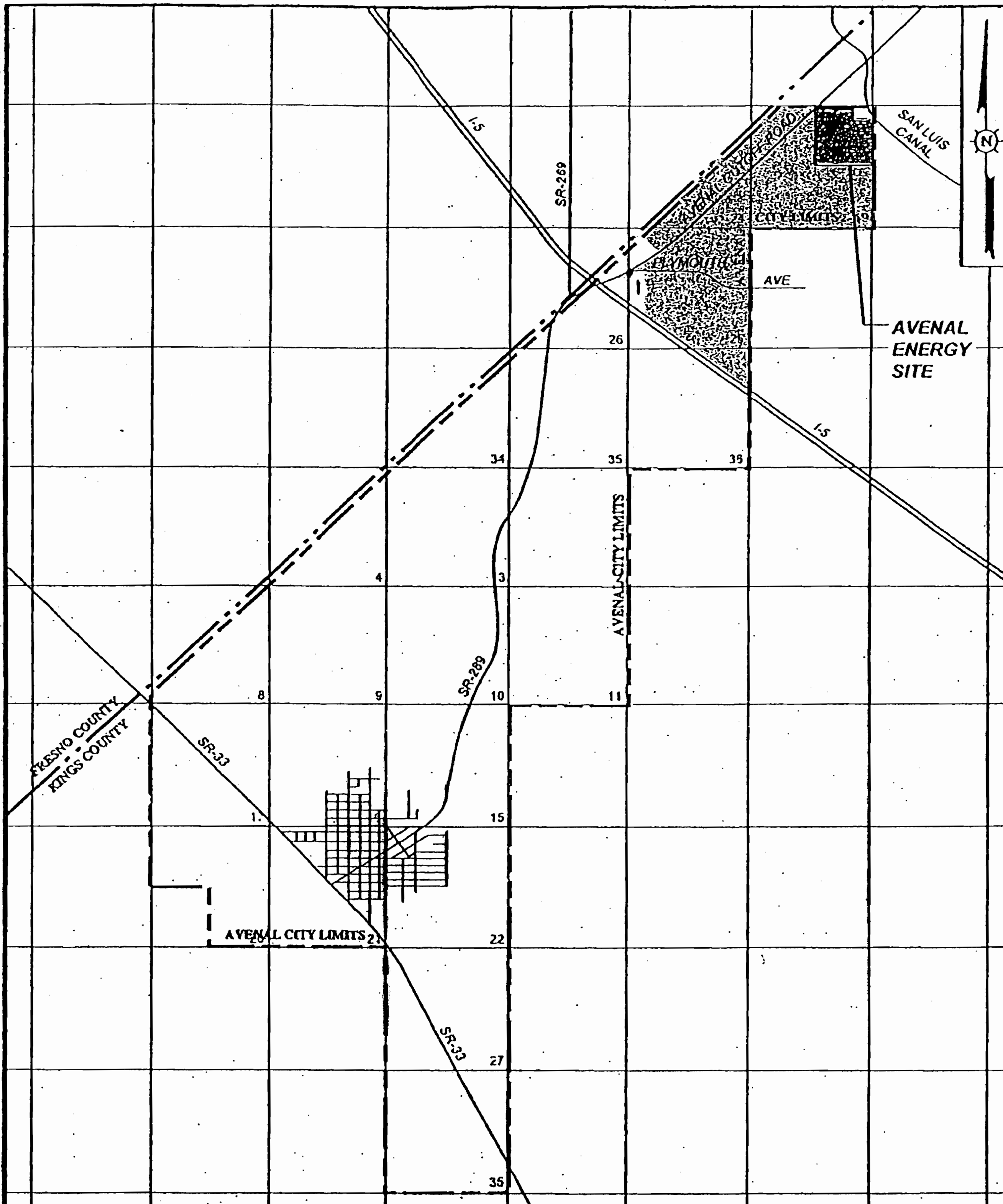



REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

| | |
|---|---|
| *AVENAL ENERGY* | FIGURE 2.0-1 |

280317-AFC-2.0-2 REV.09/13/01




**LEGEND**

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET
SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

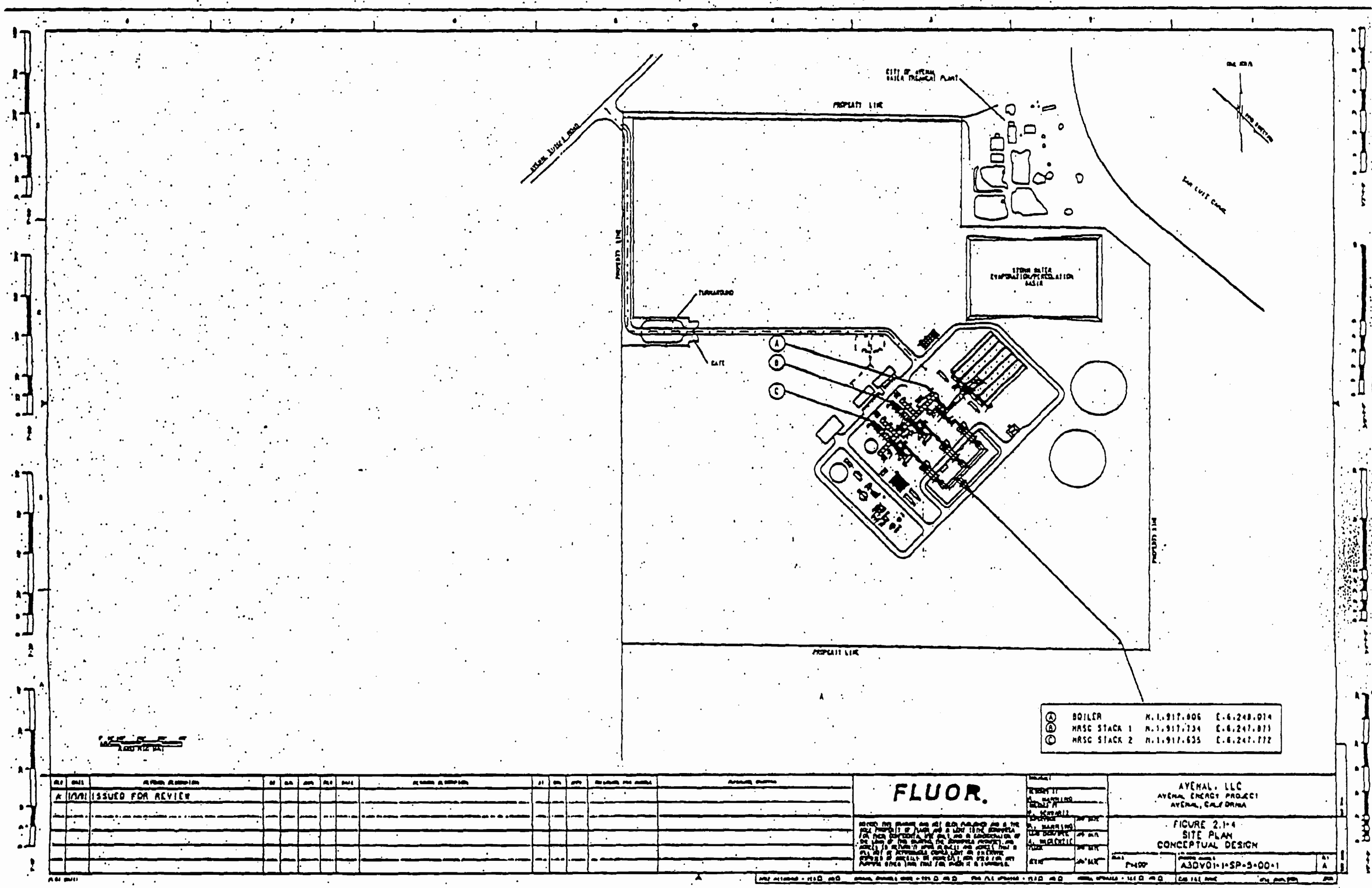
1 36.074 -120.093

AV SITE LOCATION

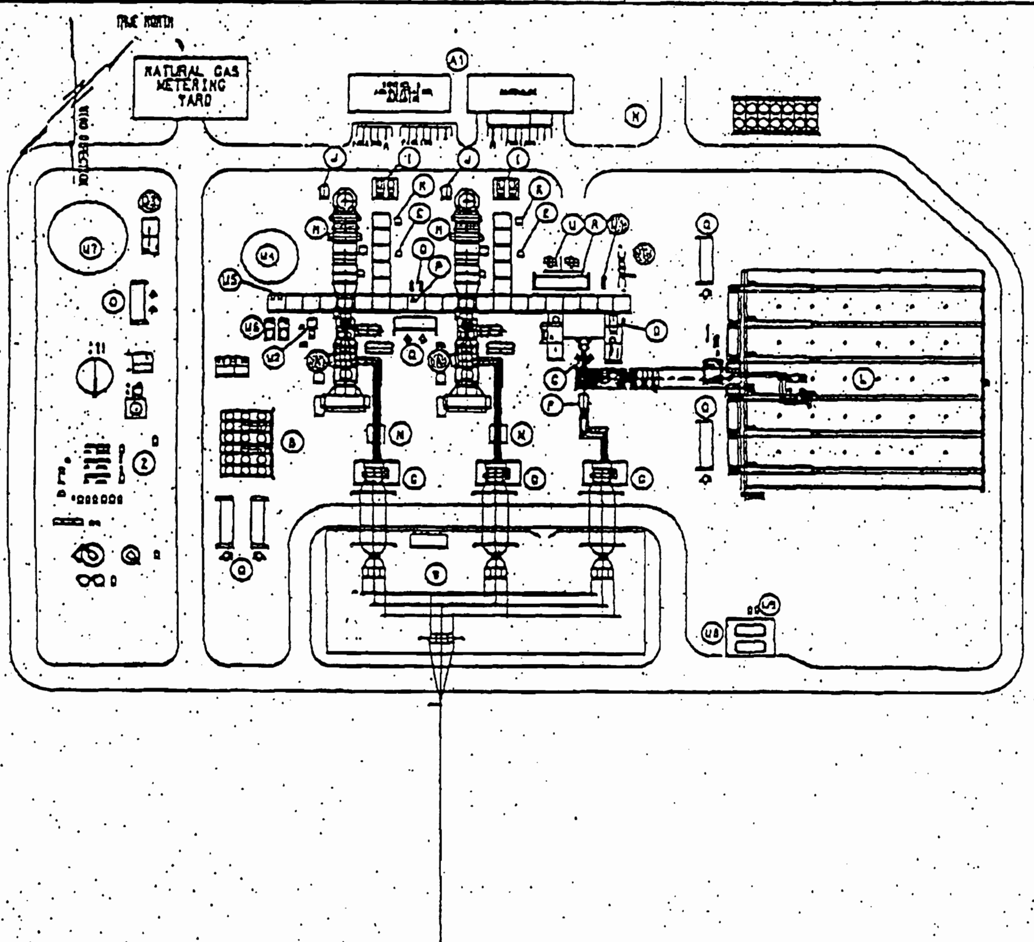
② Rd crosses horiz rd near development
36.109 -120.0486

FEDERAL POWER AVENAL, LLC

*AVENAL ENERGY* | FIGURE 2.0-2



CITY OF AVENAL WATER TREATMENT PLANT
PROPERTY LINE
TURNAROUND
GATE
STORM WATER EVAPORATION/PERCOLATION BASIN
SAN LUIS CANAL
A BOILER N.1,917,806 E.6,248,014
B HRSG STACK 1 N.1,917,734 E.6,247,873
C HRSG STACK 2 N.1,917,635 E.6,247,772
A ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1
A




**MAJOR EQUIPMENT LIST**

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
G MAIN TRANSFORMERS
H HEAT RECOVERY STEAM GENERATOR
I HP/IP BOILER FEED WATER PUMPS
J CONTINUOUS EMISSIONS MONITORING SYSTEM
K HRSG BLOWDOWN SUMP
L AIR COOLED CONDENSER
M GENERATOR BREAKERS
N CLOSED COOLING WATER AIR COOLER
O CIRCULATING COOLING WATER PUMPS
P CLOSED COOLING WATER EXPANSION TANK
Q POWER DISTRIBUTION CENTER (480 V)
R POWER DISTRIBUTION CENTER (4160 V)
S
T AUXILIARY BOILER
U UNIT AUXILIARY TRANSFORMER
V
W SWITCHYARD
X RAW WATER SOFTENER CLARIFIERS (RWSC)
Y RWSC FILTER PRESS
Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
A2 STORM WATER EVAPORATION/PERCOLATION BASIN

**UTILITIES**

U1 STANDBY DIESEL GENERATOR
U2 OIL/WATER SEPARATOR
U3 FIREWATER PUMP HOUSE
U4 DEMINERALIZED WATER STORAGE TANK
U5 DEMINERALIZED WATER PUMPS
U6 PLANT/INSTRUMENT AIR COMPRESSORS
U7 RAW WATER/FIREWATER STORAGE TANKS
U8 AMMONIA STORAGE TANKS
U9 AMMONIA TRANSFER PUMPS

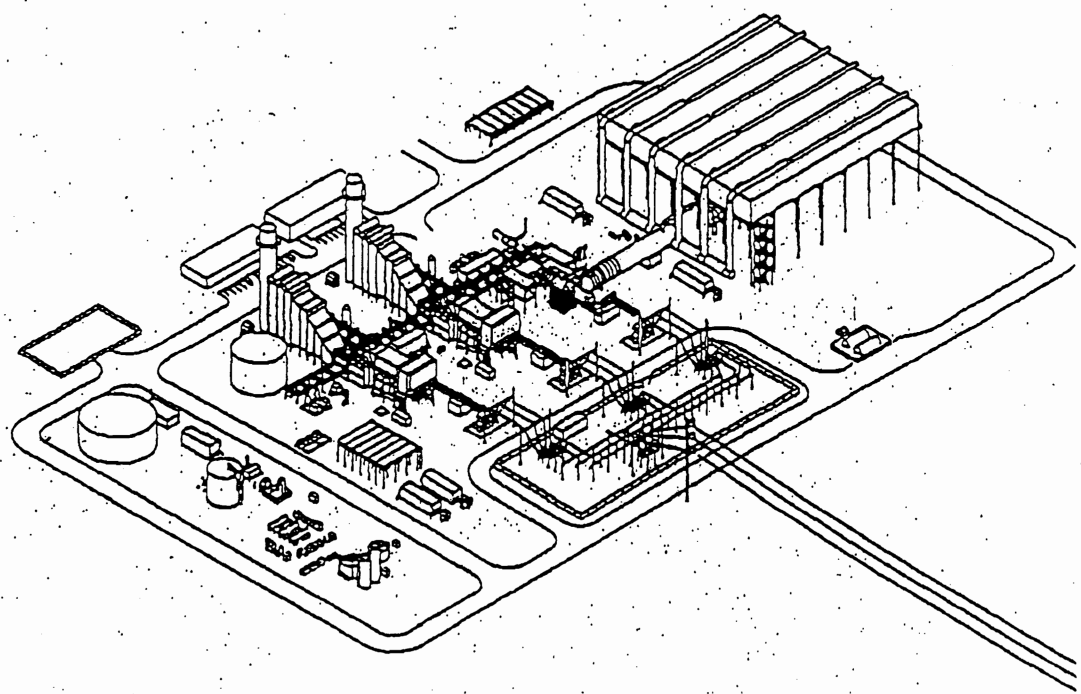
| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| A | | ISSUED FOR REVIEW | | | | | | | |

FLUOR

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

P-1261 A3DY01-1-PP-0-00-1 A



| | |
|---|---|
| A | ISSUED FOR REVIEW |

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

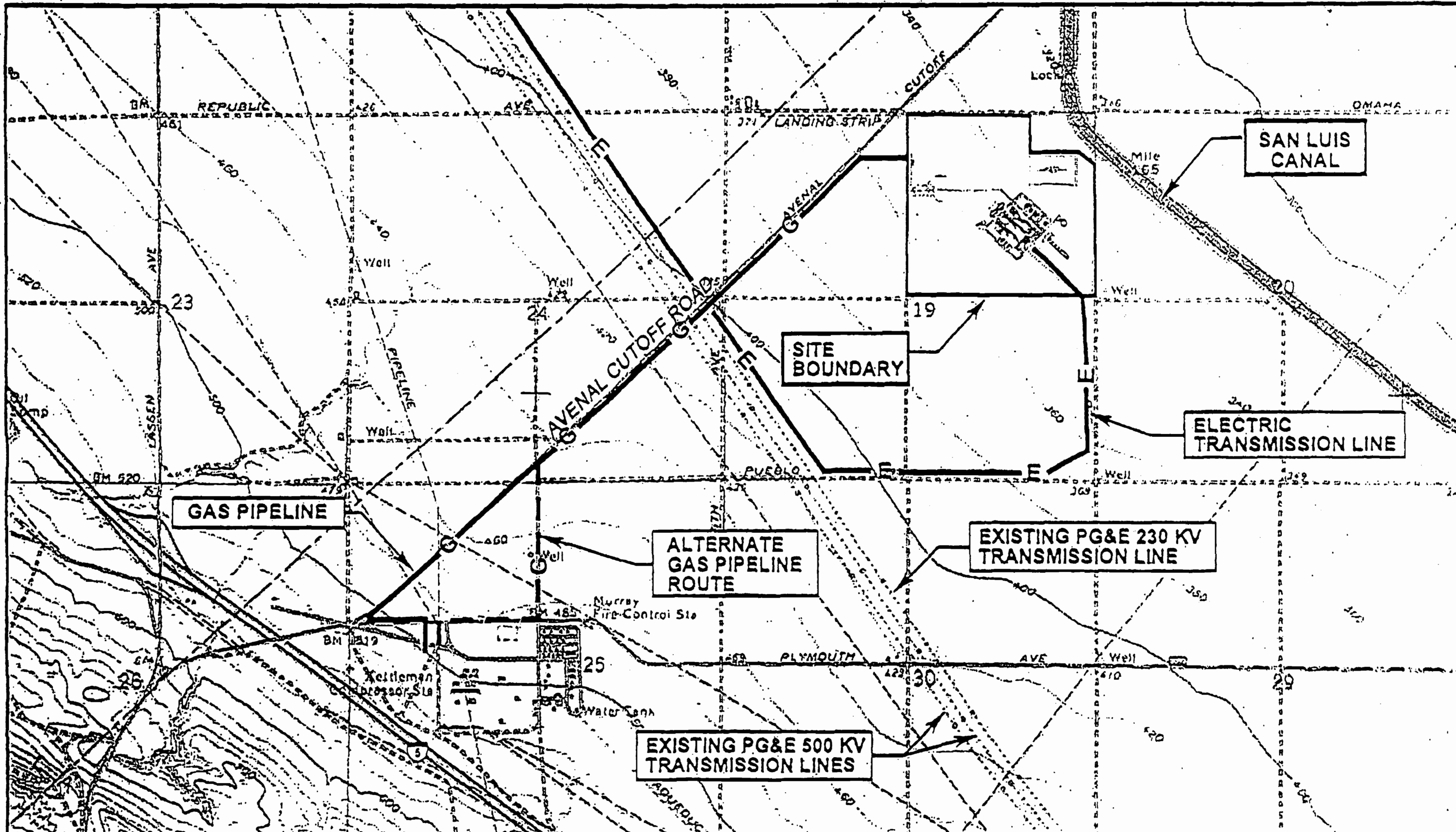
ISO VIEW
CONCEPTUAL DESIGN

NONE

A30Y01-1-PP-0-00-2

A

290317-AFC-2.1-1A REV. 09/05/06




REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

| | |
|---|---|
| *AVENAL ENERGY* | FIGURE 2.1-1A |

# ATTACHMENT D

## _CTG Emissions Data_

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

**TABLE 6.2-22**
**MAXIMUM FACILITY FUEL USE, MMBTU (HHV)**

| Period | Gas Turbines and Duct Burners (each[a]) | Auxiliary Boiler | Total Fuel Use (all Units) |
|---|---|---|---|
| Per Hour | 2,356.5 | 37.4 | 4,750 |
| Per Day | 56,555[b] | 449[c] | 113,111[d] |
| Per Year | 16,176,000[e] | 46,650[f] | 32,353,000[g] |

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

## *CTG Emissions During Startup and Shutdown*

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. $PM_{10}$ and $SO_2$ emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

**TABLE 6.2-23**
**FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]**

| | NOx | CO | VOC |
|---|---|---|---|
| Startup/Shutdown, lb/hour, average | 80 | 900 | 16 |
| Startup/Shutdown, lb/~~start,~~ hour maximum | 160 | 1,000 | 16 |

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

*CTG Emissions During Commissioning*

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the $NO_x$ emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, $NO_x$ and CO levels could again be affected.

*Noncriteria Pollutant Emissions*

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

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[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.
[25] Currently 187 substances are listed.

# ATTACHMENT D

***CTG Emissions Data***

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

| | Case 1 101°F Full Load w/ DB[1] | Case 5 63°F Full Load w/ DB[1] | Case 9 32°F Full Load w/ DB[1] | Case 2 101°F Full Load no DB | Case 6 63°F Full Load no DB | Case 10 32°F Full Load no DB | Case 4 101°F 50% Load | Case 8 63°F 50% Load | Case 12 32°F 50% Load |
|---|---|---|---|---|---|---|---|---|---|
| Ambient Temp, °F | 101 | 63 | 32 | 101 | 63 | 32 | 101 | 63 | 32 |
| GT Load, % | 100% | 100% | 100% | 100% | 100% | 100% | 50% | 50% | 50% |
| Both GTs Gross Power, MW | 344.8 | 345.0 | 359.0 | 345.5 | 345.8 | 359.5 | 144.1 | 168.8 | 183.2 |
| STG Gross Power, MW | 290.8 | 273.3 | 254.7 | 171.6 | 176.1 | 177.7 | 118.3 | 127.6 | 130.6 |
| Plant Gross Power Output, MW | 635.6 | 618.3 | 613.7 | 517.2 | 521.7 | 537.2 | 262.5 | 296.2 | 313.9 |
| Plant Net Power Output, MW | 600.0 | 600.0 | 600.0 | 483.7 | 506.5 | 525.5 | 250.3 | 286.3 | 304.8 |
| GTs Fuel Flow, kpph | 156.4 | 156.4 | 161.8 | 156.4 | 156.4 | 161.8 | 87.2 | 96.2 | 102.2 |
| DBs Fuel Flow, kpph | 49.0 | 39.8 | 31.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| GTs Heat Input, MMBtu/hr (HHV) | 1,794.2 | 1,794.3 | 1,855.4 | 1,795.6 | 1,795.4 | 1,856.3 | 1,001.4 | 1,104.3 | 1,171.9 |
| DBs Heat Input, MMBtu/hr (HHV) | 562.3 | 454.4 | 356.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total Heat Input, MMBtu/hr (HHV) | 2,356.5 | 2,248.6 | 2,211.8 | 1,795.6 | 1,795.4 | 1,856.3 | 1,001.4 | 1,104.3 | 1,171.9 |
| Stack Flow, lb/hr | 3,653,000 | 3,650,000 | 3,759,000 | 3,628,000 | 3,630,000 | 3,743,000 | 2,232,700 | 2,336,800 | 2,413,300 |
| Stack Flow, acfm | 1,044,365 | 1,025,495 | 1,069,836 | 1,051,631 | 1,037,822 | 1,071,653 | 620,528 | 644,316 | 666,146 |
| Stack Temp, °F | 195.3 | 184.9 | 189.0 | 207.4 | 198.8 | 200.9 | 180.2 | 175.8 | 177.4 |
| Stack exhaust, vol% | | | | | | | | | |
| $O_2$ (dry) | 11.40% | 11.87% | 12.34% | 13.76% | 13.77% | 13.78% | 14.46% | 14.11% | 13.93% |
| $CO_2$ (dry) | 5.42% | 5.16% | 4.89% | 4.09% | 4.08% | 4.08% | 3.70% | 3.89% | 3.89% |
| $H_2O$ | 10.54% | 10.03% | 9.12% | 8.39% | 8.28% | 7.78% | 8.07% | 7.97% | 7.63% |
| Emissions | | | | | | | | | |
| $NO_x$, ppmvd @ 15% $O_2$ | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 |
| $NO_x$, lb/hr[2] | 17.13 | 16.34 | 16.06 | 13.03 | 13.03 | 13.47 | 7.26 | 8.01 | 8.51 |
| $NO_x$, lb/MMBtu (HHV) | 0.0073 | 0.0073 | 0.0073 | 0.0073 | 0.0073 | 0.0073 | 0.0073 | 0.0073 | 0.0073 |
| $SO_2$, ppmvd @ 15% $O_2$ [3] | 0.139 | 0.139 | 0.140 | 0.140 | 0.140 | 0.140 | 0.140 | 0.140 | 0.140 |
| $SO_2$, lb/hr[2,3] | 1.66 | 1.59 | 1.56 | 1.27 | 1.27 | 1.31 | 0.71 | 0.78 | 0.83 |
| $SO_2$, lb/MMBtu (HHV)[3] | 0.0007 | 0.0007 | 0.0007 | 0.0007 | 0.0007 | 0.0007 | 0.0007 | 0.0007 | 0.0007 |
| CO, ppmvd @ 15% $O_2$ | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 | 4.0 |
| CO, lb/hr[2] | 20.86 | 19.90 | 19.56 | 15.86 | 15.86 | 16.39 | 8.84 | 9.75 | 10.36 |
| CO, lb/MMBtu (HHV) | 0.0089 | 0.0088 | 0.0088 | 0.0088 | 0.0088 | 0.0088 | 0.0088 | 0.0088 | 0.0088 |
| VOC, ppmvd @ 15% $O_2$[4] | 2.0 | 2.0 | 2.0 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 | 1.4 |
| VOC, lb/hr[2,4] | 5.98 | 5.68 | 5.59 | 3.17 | 3.17 | 3.28 | 1.77 | 1.95 | 2.07 |
| VOC, lb/MMBtu (HHV)[4] | 0.0025 | 0.0025 | 0.0025 | 0.0018 | 0.0018 | 0.0018 | 0.0018 | 0.0018 | 0.0018 |
| $PM_{10}$, lb/hr[2,5] | 11.81 | 11.27 | 10.78 | 9.00 | 9.00 | 9.00 | 9.00 | 9.00 | 9.00 |
| $PM_{10}$, lb/MMBtu (HHV)[5] | 0.0050 | 0.0050 | 0.0049 | 0.0050 | 0.0050 | 0.0048 | 0.0090 | 0.0081 | 0.0077 |
| $PM_{10}$, gr/SCF (dry)[5] | 0.00189 | 0.00179 | 0.00165 | 0.00142 | 0.00142 | 0.00137 | 0.00230 | 0.00220 | 0.00212 |
| $NH_3$, ppmvd @ 15% $O_2$ | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 | 10.0 |
| $NH_3$, lb/hr[2] | 35.39 | 33.57 | 32.88 | 26.28 | 26.25 | 26.98 | 14.60 | 16.08 | 17.02 |
| $CO_2$, lb/MMBtu (HHV)[7] | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 | 117.0 |
| $CH_4$, lb/MMBtu (HHV)[6] | 0.013 | 0.013 | 0.013 | 0.013 | 0.013 | 0.013 | 0.013 | 0.013 | 0.013 |
| $N_2O$, lb/MMBtu (HHV)[6] | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 | 0.00022 |
| $CO_2$, lb/hr[8] | 275,599 | 262,984 | 258,674 | 210,000 | 209,976 | 217,102 | 117,114 | 129,153 | 137,055 |
| $CH_4$, lb/hr[8] | 30.7 | 29.2 | 28.8 | 23.4 | 23.4 | 24.1 | 13.0 | 14.4 | 15.2 |
| $N_2O$, lb/hr[8] | 0.52 | 0.50 | 0.49 | 0.40 | 0.40 | 0.41 | 0.22 | 0.24 | 0.26 |

1) Includes duct burner firing only up to plant maximum output of 600 MW.

2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.

3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to $SO_2$ with no $SO_3$ conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) $CH_4$ emission factor (kg/MMBtu) = 0.0059

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

7) $CO_2$ emission factor (kg/MMBtu) = 53.06

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) $N_2O$ emission factor (kg/MMBtu) = 0.0001

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

# ATTACHMENT E

## *SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2*

San Joaquin Valley
Unified Air Pollution Control District

**Best Available Control Technology (BACT) Guideline 1.1.2***

Last Update: 3/14/2002

## Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | Natural gas fuel with LPG backup | | |
| NOx | 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system ( if the igniter system is used to heat the boiler at low fire). | 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system ( if the igniter system is used to heat the boiler at low fire). | |
| PM10 | Natural gas fuel with LPG backup | | |
| SO | Natural gas fuel with LPG backup | | |
| VOC | Natural gas fuel with LPG backup | | |

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

# San Joaquin Valley
# Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

## Emergency Diesel I.C. Engine Driving a Fire Pump

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | | Oxidation Catalyst | |
| NOx | Certified NOx emissions of 6.9 g/bhp-hr or less | | |
| PM10 | 0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered) | | |
| SOx | Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available. | | |
| VOC | Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification] | Catalytic Oxidation | |

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

### Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | = or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal) | 90% control efficiency (Oxidation catalyst, or equal) | > or = 80% control efficiency (Rich-burn engine with NSCR, or equal) |
| NOx | = or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal) | | = or > 90% control efficiency (Rich-burn engine with NSCR, or equal) |
| PM10 | Natural gas fuel | | |
| VOC | = or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal) | 90% control efficiency (Oxidation catalyst, or equal) | = or > 50% control efficiency (Rich-burn engine with NSCR, or equal) |

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

# San Joaquin Valley
# Unified Air Pollution Control District

## Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

## Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

| Pollutant | Achieved in Practice or contained in the SIP | Technologically Feasible | Alternate Basic Equipment |
|---|---|---|---|
| CO | 6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal) | 4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal) | |
| NOx | 2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal) | 2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal) | |
| PM10 | Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal | | |
| SOx | 1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal. | | |
| VOC | 2.0 ppmv @ 15% O2 | 1.5 ppmv @ 15% O2 | |

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

# ATTACHMENT F

***Top Down BACT Analysis***
***(C-3953-10-1, -11-1, -12-1, -13-1, and –14-1)***

**Units C-3953-10-1 and –11-1 (Turbines)**

**I. $NO_X$ Top-Down BACT Analysis**

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with $NO_X$ emissions of 2.0 ppmv @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve $NO_X$ emissions of less than or equal to 2.0 ppmv @ 15% $O_2$ (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

**Units C-3953-10-1 and –11-1 (Turbines)**

## II. VOC Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% $O_2$

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% $O_2$

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. 1.5 ppmvd VOC @ 15% $O_2$
2. 2.0 ppmvd VOC @ 15% $O_2$

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% $O_2$ when the unit is fired without the duct burner and 2.0 ppmvd @ 15% $O_2$ when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% $O_2$ did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% $O_2$ emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% $O_2$. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% $O_2$; therefore, BACT is satisfied.

**Units C-3953-10-1 and –11-1 (Turbines)**

## III. $PM_{10}$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

**General control for $PM_{10}$ emissions include the following options:**

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

**Units C-3953-10-1 and –11-1 (Turbines)**

## IV. $SO_X$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

**Units C-3953-12-1 (Boiler)**

**I. $NO_X$ Top-Down BACT Analysis**

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv $NO_X$ @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv $NO_X$ @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% $O_2$. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be $NO_X$ emissions of less than 9.0 ppmvd @ 3% $O_2$. The facility has proposed $NO_X$ emissions of less than 9.0 ppmv @ 3% $O_2$. Therefore, BACT is satisfied.

**Units C-3953-12-1 (Boiler)**

**II. VOC Top-Down BACT Analysis**

**Step 1 - Identify All Possible Control Technologies**

**General control for VOC emissions include the following options:**

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Natural gas fuel with LPG backup

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

**Units C-3953-12-1 (Boiler)**

## III. $PM_{10}$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

**General control for $PM_{10}$ emissions include the following options:**

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All of the listed controls are considered technologically feasible for this application.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

1. Natural gas fuel with LPG backup

**Step 4 - Cost Effectiveness Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

**Units C-3953-13-1 (Diesel IC engine powering fire water pump)**

## I. $NO_X$ Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified $NO_X$ emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their emission factor:

1. Certified $NO_X$ emissions of 6.9 g/bhp-hr or less

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be Certified $NO_X$ emissions of 6.9 g/bhp-hr or less. The facility has proposed $NO_X$ emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

**Units C-3953-13-1 (Diesel IC engine powering fire water pump)**

## II. VOC Top-Down BACT Analysis

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

**Step 5 - Select BACT**

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

**Units C-3953-14-1 (Natural gas IC engine powering electrical generator)**

## I. $NO_X$ Top-Down BACT Analysis

### Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- $NO_X$ emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

### Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

### Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)
2. $NO_X$ emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

### Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

**1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)**

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for $NO_X$ reduction is $9,700 per ton of $NO_X$ reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of ≤ 1.0 g $NO_X$/hp-hr, the District will assume that the Industry Standard will be 2.8 g $NO_X$/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled $NO_X$ value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g $NO_X$/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g $NO_X$/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g $NO_X$/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>$NO_X$ (annual):</u>

$$\frac{2.8\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 265\ lb\ NO_X/year$$

*$PE_{NOx}$ = 265 lb $NO_X$/year = 0.1325 tons $NO_X$/year*

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a $NO_X$ control efficiency of ≥ 90% can be calculated as:

<u>$NO_X$ (annual):</u>

$$\frac{7.4\ \cancel{g}^{(1)}}{\cancel{hp\text{-}hr}} \times \frac{(1-0.9)}{1} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 70\ lb\ NO_X/year$$

*$PE_{NOx}$ = 70 lb $NO_X$/year = 0.035 tons $NO_X$/year*

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$$

[1] Pursuant to AP-42 (07/00) the $NO_X$ value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

$CE_{alt}$ = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately \$28,000, the capital cost for installing an air to fuel ratio controller would be \$5,300, and the overall installation cost would be \$2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between \$8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of \$1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A\ (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where: A = Equivalent annual capital cost of the control equipment
P = Present value of the control equipment including installation
i = interest rate (10% used as default value)
n = equipment life (10 years used as default value)

Using a total capital cost of \$35,800 in the above equation results in an equivalent annual cost of \$5,826/year. Adding this equivalent annual cost to the annual operating cost of \$1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to \$6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control $NO_X$, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:

$E_{NOx}$ = tons-$NO_X$ controlled/yr
$E_{CO}$ = tons-CO controlled/yr
$E_{VOC}$ = tons-VOC controlled/yr
$T_{NOx}$ = District's cost effectiveness threshold for $NO_X$
= \$9,700/ton-$NO_X$
$T_{CO}$ = District's cost effectiveness threshold for CO
= \$300/ton-CO
$T_{VOC}$ = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt}$ – $Cost_{basic}$), to determine if this control technology is cost effective.

To determine $E_{CO}$, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with $NO_X$ emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173 \text{ lb CO/year}$$

_$PE_{CO}$ = 173 lb CO/year = 0.0865 ton CO/year_

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

CO (annual):

$$\frac{11.6\ \cancel{g}^{(2)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.8)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

*$PE_{CO}$ = 220 lb CO/year = 0.11 ton CO/year*

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine $E_{VOC}$, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with $NO_X$ emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}} \left| \frac{860\ \cancel{hp}}{1} \right| \frac{lb}{453.6\ \cancel{g}} \left| \frac{50\ \cancel{hr}}{year} \right. = 37\ lb\ VOC/year$$

*$PE_{VOC}$ = 37 lb VOC/year = 0.0185 ton VOC/year*

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

VOC (annual):

$$\frac{0.10\ \cancel{g}^{(3)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.5)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

*$PE_{VOC}$ = 5 lb VOC/year = 0.0025 ton VOC/year*

---

[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)
[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

$E_{NOx}$ = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
$E_{VOC}$ = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET ($/yr) = (0.0975 x $9,700) + (0.016 x $5,000) = $1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to $6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

**2. $NO_X$ emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)**

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - <u>Select BACT</u>**

BACT for the emission unit is determined to be $NO_X$ emissions of 1.0 g/bhp-hr or less. The facility has proposed $NO_X$ emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

**Units C-3953-14-1 (Natural gas IC engine powering electrical generator)**

**II. VOC Top-Down BACT Analysis**

**Step 1 - Identify All Possible Control Technologies**

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

**Step 2 - Eliminate Technologically Infeasible Options**

All control options listed in step 1 are technologically feasible.

**Step 3 - Rank Remaining Control Technologies by Control Effectiveness**

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

**Step 4 - Cost Effective Analysis**

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

**Step 5 - Select BACT**

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

# ATTACHMENT G

## ***Health Risk Assessment and Ambient Air Quality Analysis***

# San Joaquin Valley Unified
# Air Pollution Control District

## MEMORANDUM

**DATE:** June 14, 2014

**TO:** Derek Fukuda, AQE—Permit Services

**FROM:** Leland Villalvazo, SAQS—Technical Services

**SUBJECT:** Revised $NO_2$ 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for $NO_2$. The previous assessment was based on the State standard of 339 ug/m$^3$ whereas the new federal standard 188.68 ug/m$^3$. The assessment contained in this memo will primarily address the new federal $NO_2$ NAAQS and any updates needed to the previous RMR assessment.

**Background:**
EPA has revised the primary $NO_2$ NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m$^3$), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for $NO_2$ monitoring network that will include monitors at locations where maximum $NO_2$ concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide $NO_2$ concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

**Results:**
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new $NO_2$ 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour $NO_2$ Standard".

| **Commissioning** | Modeling | Design Value | Impact | NAAQS Limit | Pass / Fail | Margin |
|---|---|---|---|---|---|---|
| District Tiers | ug/m3 | | | | | |
| Tier I (max yr) | **142.21** | **103.15** | 245.36 | 188.68 | F | -56.68 |
| Tier II (max 8th) | **90.10** | **103.15** | 193.25 | 188.68 | F | -4.57 |
| Tier III (ave.5yr) | **71.94** | **103.15** | 175.09 | 188.68 | **P** | 13.58 |
| Tier IV | **140.37** | | 140.37 | 188.68 | **P** | 48.31 |

| Year | 2004 | 2005 | 2006 | 2007 | 2008* | Max |
|---|---|---|---|---|---|---|
| Tier I (max yr) | **142.21398** | **107.17307** | **110.4651** | **109.99858** | **105.1162** | **142.21** |
| Tier II (max 8th) | **80.85338** | **85.86045** | **84.64008** | **88.85226** | **90.10016** | **90.1** |

*Ozone from Visalia

| **Operational** | Modeling | Design Value | Impact | NAAQS Limit | Pass / Fail | Margin |
|---|---|---|---|---|---|---|
| District Tiers | ug/m3 | | | | | |
| Tier I (max yr) | **152.79** | **103.15** | 255.94 | 188.68 | F | -67.26 |
| Tier II (max 8th) | **87.94** | **103.15** | 191.09 | 188.68 | F | -2.41 |
| Tier III (ave.5yr) | **82.43** | **103.15** | 185.58 | 188.68 | **P** | 3.10 |
| Tier IV | | | 0.00 | 188.68 | P | 188.68 |

| Year | 2004 | 2005 | 2006 | 2007 | 2008* | Max |
|---|---|---|---|---|---|---|
| Tier I (max yr) | **152.79148** | **91.1532** | **93.47387** | **93.23991** | **90.56206** | **152.79** |
| Tier II (max 8th) | **87.7931** | **86.3495** | **86.51813** | **87.38902** | **87.93997** | **87.94** |

*Ozone from Visalia

**Conclusion**

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

**Conditions**

1. $PM_{10}$ emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

| **Commissioning** | Modeling | Design Value | Impact | NAAQS Limit | Pass / Fail | Margin |
|---|---|---|---|---|---|---|
| District Tiers | | | ug/m3 | | | |
| Tier I (max yr) | **142.21** | **103.15** | 245.36 | 188.68 | F | -56.68 |
| Tier II (max 8th) | **90.10** | **103.15** | 193.25 | 188.68 | F | -4.57 |
| Tier III (ave.5yr) | **71.94** | **103.15** | 175.09 | 188.68 | P | 13.58 |
| Tier IV | **140.37** | | 140.37 | 188.68 | P | 48.31 |

| Year | 2004 | 2005 | 2006 | 2007 | 2008* | Max |
|---|---|---|---|---|---|---|
| Tier I (max yr) | **142.21398** | **107.17307** | **110.4651** | **109.99858** | **105.1162** | **142.21** |
| Tier II (max 8th) | **80.85338** | **85.86045** | **84.64008** | **88.85226** | **90.10016** | **90.1** |

*Ozone from Visalia

| **Operational** | Modeling | Design Value | Impact | NAAQS Limit | Pass / Fail | Margin |
|---|---|---|---|---|---|---|
| District Tiers | | | ug/m3 | | | |
| Tier I (max yr) | **152.79** | **103.15** | 255.94 | 188.68 | F | -67.26 |
| Tier II (max 8th) | **87.94** | **103.15** | 191.09 | 188.68 | F | -2.41 |
| Tier III (ave.5yr) | **82.43** | **103.15** | 185.58 | 188.68 | P | 3.10 |
| Tier IV | | | 0.00 | 188.68 | P | 188.68 |

| Year | 2004 | 2005 | 2006 | 2007 | 2008* | Max |
|---|---|---|---|---|---|---|
| Tier I (max yr) | **152.79148** | **91.1532** | **93.47387** | **93.23991** | **90.56206** | **152.79** |
| Tier II (max 8th) | **87.7931** | **86.3495** | **86.51813** | **87.38902** | **87.93997** | **87.94** |

*Ozone from Visalia

# Diesel I.C. Engines (DICE)
## Screening Risk Tool

### Project Information

Region: C
Facility ID: 3953
Unit #: 13-1
Project #: 110751
Date: 7/14/2010

### Met Station

| | |
|---|---|
| District | SJVAPCD |
| Met Site | HANFORD |
| Model Type | RURAL |
| Year: | 2008 |

### Engine Data

| | |
|---|---|
| BHP: | 288 |
| % Load: | 100 |
| PM10 EF (g/BHP): | 0.059 |
| Hours / Yr: | 100 |
| Lbs / Yr: | 3.75 |

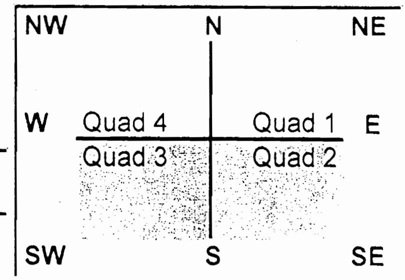
Convert to G/BHP

Convert to G/KW

Update Emissions

### Receptor Data

Quad: QUAD 1
Distance(m): 50
Miles:
Feet:
Yards:
10th Mi:




### Cancer Risk

Resident Risk: In a Million 0.24
Maximum Res. Risk: 1.98
Worker Adjustment Factor %: 37.91
Worker Risk: In a Million 0.09
Maximum Worker Risk: 0.75
Quad: 2
Distance: 50

Calculate Risk

Print Form

**New** **View Eng Data** **SAVE** **Close Form**

14-1

Print Worksheet

# INTERNAL COMBUSTION (NG) EMISSION FACTORS (LBS. / MMCF)

FACILITY NAME:
DATE:

Receptor Distance: 1206

**Priority Score** 0.092999134

Total hrs. of operation 50.00 | MMCF/HR 0.0071 | MMCF/YR 0.36

| POLLUTANT | EMISSION FACTOR (MMCF/HR) <1000 | >1000 | TURBINE | Acute REL | Chronic REL | Cancer URF |
|---|---|---|---|---|---|---|
| Acetaldehyde | 0.944 | 1.1328 | 0.037 | 0 | 9 | 2.70E-06 |
| Acrolein | 0.3783 | 0.454 | 0.009 | 0.19 | 2.00E-02 | 0 |
| Benzene | 3.257 | 3.9084 | 0.0113 | 1300 | 71 | 2.90E-05 |
| Formaldehyde | 32.4963 | 38.9956 | 0.094 | 94 | 3.6 | 6.00E-06 |
| Naphthalene | 0.1785 | 0.1785 | 0.0008 | 0 | 14 | 0 |
| PAH's | 0.0179 | 0.0179 | 0.0002 | 0 | | 1.70E-03 |
| Propylene | 16.2259 | 19.4711 | 1.0522 | 0 | 0 | 0 |
| Toluene | 1.1145 | 1.3374 | 0.0726 | 37000 | 200 | 0 |
| Xylenes | 0.4048 | 0.4858 | 0.0289 | 22000 | 300 | 0 |
| Ethyl Benzene | 0.3257 | 0.3908 | 0.0132 | 0 | 0 | 0 |
| Hexane | 0.7491 | 0.8989 | 1.75 | 0 | 0 | 0 |

| | <1000 EMISSION FACTORS | LBS./HR. | G/SEC | LBS./YR. | G/SEC | Acute Score | Chronic Score | Carcinogenic Score | Non-Carcinogenic Score |
|---|---|---|---|---|---|---|---|---|---|
| Acetaldehyde | 0.944 | 6.70E-03 | **8.45E-04** | 3.35E-01 | **4.82E-06** | 0 | 0.11170667 | 0.001538201 | 0.111706667 |
| Acrolein | 0.3783 | 2.69E-03 | **3.39E-04** | 1.34E-01 | **1.93E-06** | 21.204711 | 20.144475 | 0 | 21.20471053 |
| Benzene | 3.257 | 2.31E-02 | **2.92E-03** | 1.16E+00 | **1.66E-05** | 0.0266823 | 0.048855 | 0.057002386 | 0.048855 |
| Formaldehyde | 32.4963 | 2.31E-01 | **2.91E-02** | 1.15E+01 | **1.66E-04** | 3.6817616 | 9.61348875 | 0.117669102 | 9.61348875 |
| Naphthalene | 0.1785 | 1.27E-03 | **1.60E-04** | 6.34E-02 | **9.12E-07** | 0 | 0.01357875 | 0 | 0.01357875 |
| PAH's | 0.0179 | 1.27E-04 | **1.60E-05** | 6.35E-03 | **9.15E-08** | 0 | 0 | 0.018364505 | 0 |
| Propylene | 16.2259 | 1.15E-01 | **1.45E-02** | 5.76E+00 | **8.29E-05** | 0 | 0 | 0 | 0 |
| Toluene | 1.1145 | 7.91E-03 | **9.98E-04** | 3.96E-01 | **5.70E-06** | 0.0003208 | 0.00593471 | 0 | 0.005934713 |
| Xylenes | 0.4048 | 2.87E-03 | **3.62E-04** | 1.44E-01 | **2.07E-06** | 0.000196 | 0.00143704 | 0 | 0.00143704 |
| Ethyl Benzene | 0.3257 | 2.31E-03 | **2.92E-04** | 1.16E-01 | **1.66E-06** | 0 | 0 | 0 | 0 |
| Hexane | 0.7491 | 5.32E-03 | **6.71E-04** | 2.66E-01 | **3.83E-06** | 0 | 0 | 0 | 0 |

# San Joaquin Valley Unified Air Pollution Control District

## MEMORANDUM

**DATE:** June 25, 2002

**TO:** Errol Villegas, SAQE—Permit Services

**FROM:** Esteban Gutierrez, AQS—Technical Services

**SUBJECT:** AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and $PM_{10}$; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

### RMR Modeling Results

| REFINED HRA SUMMARY | | | |
|---|---|---|---|
| **Device** | **(2) Turbines** | **Boiler** | **(3) 4 cell tower** |
| **Fuel** | **NG** | **NG** | |
| **Prioritization Score** | 0.8242 | .0107 | N/A |
| **Cancer Risk** | N/A | N/A | N/A |
| **Acute Hazard Index** | N/A | N/A | N/A |
| **Chronic Hazard Index** | N/A | N/A | N/A |
| **TBACT Required?** | No | No | No |

| REFINED HRA SUMMARY | | | |
|---|---|---|---|
| **Device** | **7 cell tower** | **300 Hp ICE** | **660 HP ICE** |
| **Fuel** | | **Diesel** | **Diesel** |
| **Prioritization Score** | N/A | N/A | N/A |
| **Cancer Risk** | N/A | 2.01E-6 | 1.00E-6 |
| **Acute Hazard Index** | N/A | N/A | N/A |
| **Chronic Hazard Index** | N/A | N/A | N/A |
| **Maximum operating Hrs** | | 200 | 38 |
| **TBACT Required?** | No | Yes | No |

**Criteria Pollutant Modeling Results***

Values are in ug/m$^3$

| | 1 Hour | 3 Hours | 8 Hours. | 24 Hours | Annual |
|---|---|---|---|---|---|
| CO | Pass | X | Pass | X | X |
| $NO_x$ | Pass*** | X | X | X | Pass |
| $SO_x$ | Pass | Pass | X | Pass | Pass |
| $PM_{10}$ | X | X | X | Pass** | Pass** |

*Results were taken from the attached PSD spreadsheet.
**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.
*** Passing score was obtained from running OLM (Ozone Limiting Method.)

| (2) NG Turbines Stack Parameters | | | |
|---|---|---|---|
| **Source Type** | Point | **Process Rate (T1) MMbtu/yr** | 16,958,390 |
| **Stack Height (m)** | 44.2 | **Process Rate (T2) MMbtu/yr** | 20,582,010 |
| **Stack Diam. (m)** | 5.49 | **Hours of operation yr (T1)** | 8400 |
| **Gas Exit Velocity (m/sec) T1** | 20.4 | **Hours of operation yr (T2)** | 8760 |
| **Stack Gas Temp (°K)** | 356 | **Receptor Distance (m)** | 1609 |
| **Location Type** | Rural | | |

| 7 Cell Cooling Tower Stack Parameters | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 13.7 | **Process Rate Gal/Yr** | 57,153,744,000 |
| **Stack Diam. (m)** | 9.64 | **Receptor Distance (m)** | 1609 |
| **Gas Exit Velocity (m/sec)** | 8.10 | **Hours of operation** | 8760 |
| **Stack Gas Temp (°K)** | 293 | | |

| (3) 4 Cell Cooling Towers Stack Parameters | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 16.08 | **Process Rate Gal/Yr** | 5,308,560,000 |
| **Stack Diam. (m)** | 3.57 | **Receptor Distance (m)** | 1609 |
| **Gas Exit Velocity (m/sec)** | 11.46 | **Hours of operation** | 8760 |
| **Stack Gas Temp (°K)** | 293 | | |

| Boiler Stack Parameters | | | |
|---|---|---|---|
| **Source Type** | Point | **Location Type** | Rural |
| **Stack Height (m)** | 11.28 | **Process Rate MMbtu/yr** | 93,500 |
| **Stack Diam. (m)** | 0.812 | **Receptor Distance (m)** | 1609 |
| **Gas Exit Velocity (m/sec)** | 12.2 | **Hours of operation** | 2500 |
| **Stack Gas Temp (°K)** | 476 | | |

| Diesel Engine (300 Hp) | | | |
|---|---|---|---|
| **Source Type** | Point | **Closest Receptor (m)** | 1609 |
| **Stack Height (m)** | 3.04 | **Location Type** | RURAL |
| **Stack Diam. (m)** | 0.13 | **Max Operating (hr/yr)** | **100** |
| **Gas Exit Velocity (m/sec)** | 67.1 | **Fuel Type** | Diesel |
| **Stack Gas Temp (°K)** | 716 | **PM10 g/bhp-hr** | 0.09 |

| Diesel Engine (660 Hp) | | | |
|---|---|---|---|
| **Source Type** | Point | **Closest Receptor (m)** | 1609 |
| **Stack Height (m)** | 3.04 | **Location Type** | RURAL |
| **Stack Diam. (m)** | 0.23 | **Max Operating (hr/yr)** | **38** |
| **Gas Exit Velocity (m/sec)** | 45.0 | **Fuel Type** | Diesel |
| **Stack Gas Temp (°K)** | 799 | **PM10 g/bhp-hr** | 0.4 |

**Conclusion:**

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting $\leq$ 0.149g $PM_{10}$/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g $PM_{10}$/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.

2. $PM_{10}$ emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).

3. $PM_{10}$ emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).

4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.

5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.

6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.

7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

# ATTACHMENT H

## *$SO_X$ for $PM_{10}$ Interpollutant Offset Analysis*

# $SO_X$ for $PM_{10}$ Interpollutant Offset Analysis
# Avenal Power Center, LLC

| | | | |
|---|---|---|---|
| Facility Name: | Avenal Power Center, LLC | Date: | June 30, 2010 |
| Mailing Address: | 500 Dallas Street. Level 31<br>Houston, TX 77002 | Engineer:<br>Lead Engineer: | Derek Fukuda<br>Joven Refuerzo |
| Contact Person: | Jim Rexroad | | |
| Telephone: | (713) 275-6147 | | |
| Application #: | C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 | | |
| Project #: | C-1100751 | | |
| Location: | NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032 | | |
| Complete: | March 18, 2010 | | |

## I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide $NO_X$ emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for $NO_X$, VOC, and $PM_{10}$. There will be an increase in emissions for all pollutants and offsets are required for $NO_X$, VOC, and $PM_{10}$ emissions.

## II. Applicable Rules

**Rule 2201** New and Modified Stationary Source Review Rule (9/21/06) (Section 3.30 and 4.13.3.2)

## III. Process Description

**Combined-Cycle Combustion Turbine Generators**

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low $NO_X$ combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low $NO_X$ (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

$NO_X$: 2.0 ppmvd @ 15% $O_2$
VOC: 2.0 ppmvd @ 15% $O_2$
CO: 2.0 ppmvd @ 15% $O_2$
$SO_X$: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
$PM_{10}$: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record $NO_X$, CO, and $O_2$ concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce $NO_X$ in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts $NO_X$ to nitrogen and water, resulting in a reduced concentration of $NO_X$ in the exhaust gases exiting the stack.

**Duct Burners**

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

**Steam Turbine Generator**

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

**Auxiliary Boiler**

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low $NO_X$ burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

**Diesel-Fired Emergency IC Engine Powering a Fire Pump**

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

**Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator**
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

## IV. Equipment Listing:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW $NO_X$ COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

## V. Interpollutant Offset Ratio Proposal $SO_X$ for $PM_{10}$

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of $PM_{10}$ precursor ERCs to offset $PM_{10}$ increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-$PM_{10}$ relationship given the atmospheric chemistry and the meteorology of the locale).

The $SO_X$ for $PM_{10}$ interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall $SO_X$ for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1100751.

## IV. Project Offset Calculations

### i. C-3953-10-1 and C-3953-11-1 (Turbines)

#### *a. Maximum Hourly PE*

The maximum hourly potential to emit for $NO_X$, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

| Maximum Hourly Potential to Emit | | | | | |
|---|---|---|---|---|---|
| | Maximum Startup/Shutdown Emissions (lb/hr) | Turbine w/ Duct Burner Emissions Rate | Turbine #1 Emissions (lb/hr) | Turbine #2 Emissions (lb/hr) | Maximum Hourly Emissions for Both Turbines |
| $NO_X$ | 160 | 17.20 | 13.55 | 13.55 | 240.00 |
| CO | 1,000 | 10.60 | 8.35 | 8.35 | 1,902.00 |
| VOC | 16 | 5.89 | 3.34 | 3.34 | 32.00 |
| $PM_{10}$ | N/A(1) | 11.78 | 8.91 | 8.91 | 23.56 |
| $SO_X$ | N/A(7) | 6.65 | 5.23 | 5.23 | 13.30 |
| $NH_3$ | N/A | 32.13 | 25.31 | 25.31 | 64.26 |

### *b. Maximum Daily PE*

Maximum daily emissions for $NO_X$, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for $PM_{10}$, $SO_X$, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for $PM_{10}$, $SO_X$, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

| Maximum Daily Potential to Emit (w/ Startup and Shutdown) | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (101° F) | Emissions Rate @ 100% Load without duct burner (32° F) | DEL (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 17.20 lb/hr | 13.03 lb/hr | 789.6 lb/day |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 5,590.8 lb/day |
| VOC | 16 lb/hr (avg) | 5.89 lb/hr | 3.34 lb/hr | 202.0 lb/day |
| $PM_{10}$ | N/A(8) | 11.78 lb/hr | 8.91 lb/hr | 282.7 lb/day |
| $SO_X$ | N/A(8) | 6.65 lb/hr | 5.23 lb/hr | 159.6 lb/day |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 771.1 lb/day |

### *c. Maximum Annual PE*

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The $SO_X$ emission factors used to calculate the annual potential emissions will be based

[1] $PM_{10}$ and $SO_X$ emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

$SO_X$ EF = (0.36 ~~gr-S~~/100 ~~dscf~~) x (1 ~~lb-S~~/7000 ~~gr~~) x (64 lb $SO_X$/32 ~~lb-S~~) x (1 ~~scf~~/1013 ~~Btu~~) x ($10^6$ ~~Btu~~/MMBtu)
**= 0.001 lb-$SO_X$/MMBtu**

CTG w/o Duct Burner Firing:
$SO_X$ Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-$SO_X$/MMBtu)
= **1.86 lb-$SO_X$/hr**

CTG w/ Duct Burner Firing:
$SO_X$ Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-$SO_X$/MMBtu)
= **2.36 lb-$SO_X$/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

**Scenario 1) Weekend and Weekday Hot Start:**

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for $PM_{10}$, $SO_X$, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| **Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*** | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG)) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | **143,951 lb/year** |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 557,033 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | **34,489 lb/year** |
| $PM_{10}$ | N/A(8) | 11.27 lb/hr | 9.00 lb/hr | 74,091 lb/year |
| $SO_X$ | N/A(8) | 2.36 lb/hr | 1.86 lb/hr | 15,337 lb/year |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 208,708 lb/year |

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

**Scenario 2) Weekend Shutdown and Weekday Hot Start:**

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for $PM_{10}$, $SO_X$, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| Annual Potential to Emit<br>Scenario 2) Weekend Shutdown and Weekday Hot Start* | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | 112,506 lb/year |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 601,810 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | 26,574 lb/year |
| $PM_{10}$ | N/A(8) | 11.27 lb/hr | 9.00 lb/hr | 48,832 lb/year |
| $SO_X$ | N/A(8) | 2.36 lb/hr | 1.86 lb/hr | 10,117 lb/year |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | 137,675 lb/year |

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

**Scenario 3) Baseload:**

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

| Annual Potential to Emit Baseload Scenario* | | | | |
|---|---|---|---|---|
| | Average Startup/Shutdown Emissions Rate | Emissions Rate @ 100% Load with duct burner (63° F) | Emissions Rate @ 100% Load without duct burner (63° F) | Annual PE (per CTG) |
| $NO_X$ | 80 lb/hr (avg) | 16.34 lb/hr | 13.03 lb/hr | 116,791 lb/year |
| CO | 900 lb/hr (avg) | 10.60 lb/hr | 8.35 lb/hr | 74,946 lb/year |
| VOC | 16 lb/hr (avg) | 5.68 lb/hr | 3.17 lb/hr | 29,777 lb/year |
| $PM_{10}$ | N/A(8) | 11.27 lb/hr | 9.00 lb/hr | **80,656 lb/year** |
| $SO_X$ | N/A(8) | 2.36 lb/hr | 1.86 lb/hr | **16,694 lb/year** |
| $NH_3$ | N/A | 32.13 lb/hr | 25.31 lb/hr | **219,972 lb/year** |

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

**Maximum Annual Potential to Emit:**

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

| Maximum Annual Potential to Emit | | |
|---|---|---|
| | Annual PE (per CTG) | Scenario |
| $NO_X$ | 143,951 lb/year | Scenario 1 |
| CO | 197,928 lb/year | Facility Wide Limit |
| VOC | 34,489 lb/year | Scenario 2 |
| $PM_{10}$ | 80,656 lb/year | Scenario 3 |
| $SO_X$ | 16,694 lb/year | Scenario 3 |
| $NH_3$ | 219,972 lb/year | Scenario 3 |

**ii. C-3953-12-0 (Boiler)**

The $PM_{10}$ potential to emit for the boiler is calculated as follows, and summarized in the table below.

$PE_{PM10}$ = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb $PM_{10}$/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb $PM_{10}$/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb $PM_{10}$/year**

= (233 lb/year) $*$ (4 qtr/year)
= **58 lb $PM_{10}$/qtr**

| Post Project Potential to Emit (PE2) (C-3953-12-0) | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $PM_{10}$ | 0.19 | 2.2 | 58 | 233 |

**iii. C-3953-13-0 (Diesel IC engine powering fire water pump)**

The $PM_{10}$ emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

$PE_{PM10}$ = (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb $PM_{10}$/hr**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (24 hr/day)
= **0.9 lb $PM_{10}$/day**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (12.5 hr/qtr)
= **0.5 lb $PM_{10}$/qtr**

= (0.059 g/hp·hr) $*$ (288 hp) ÷ (453.6 g/lb) $*$ (50 hr/year)
= **1.9 lb $PM_{10}$/year**

| Post Project Potential to Emit (PE2) (C-3953-13-0) | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $PM_{10}$ | 0.04 | 0.9 | 0.5 | 2 |

**iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)**

The $PM_{10}$ emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

$PE_{PM10}$ = (0.034 g/hp·hr) $*$ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb $PM_{10}$/hr**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (24\ hr/day)$
$=$ **1.5 lb $PM_{10}$/day**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (12.5\ hr/qtr)$
$=$ **1 lb $PM_{10}$/qtr**

$= (0.034\ g/hp \cdot hr) * (860\ hp) \div (453.6\ g/lb) * (50\ hr/year)$
$=$ **3 lb $PM_{10}$/year**

| **Post Project Potential to Emit (PE2) (C-3953-14-0)** | | | | |
|---|---|---|---|---|
| | Hourly Emissions (lb/hr) | Daily Emissions (lb/day) | Quarterly Emissions (lb/qtr) | Annual Emissions (lb/year) |
| $PM_{10}$ | 0.06 | 1.5 | 1 | 3 |

**Post-Project Stationary Source Potential to Emit (SSPE2)**

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

| **Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)** | | | | | | |
|---|---|---|---|---|---|---|
| Permit Unit | $NO_X$ * | CO ** | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| C-3953-10-1 | 198,840 | 197,928 | 34,489 | 80,656 | 16,694 | 219,972 |
| C-3953-11-1 | | | 34,489 | 80,656 | 16,694 | 219,972 |
| C-3953-12-1 | | | 201 | 233 | 132 | 0 |
| C-3953-13-1 | | | 12 | 2 | 0 | 0 |
| C-3953-14-1 | | | 31 | 3 | 1 | 0 |
| Post-project SSPE (SSPE2) | **198,840** | **197,928** | **69,222** | **161,550** | **33,521** | **439,944** |

* The facility has proposed to limit the $NO_X$ emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

**Total Emissions to be Offset**

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

| Emission to be Offset (lb/year) | | | | | | |
|---|---|---|---|---|---|---|
| Permit Unit | $NO_X$ * | CO ** | VOC | $PM_{10}$ | $SO_X$ | $NH_3$ |
| C-3953-10-1 | 198,840 | 197,928 | 34,489 | 80,656 | 16,694 | 219,972 |
| C-3953-11-1 | | | 34,489 | 80,656 | 16,694 | 219,972 |
| C-3953-12-1 | | | 201 | 233 | 132 | 0 |
| Post-project SSPE (SSPE2) | **198,840** | **197,928** | **69,179** | **161,545** | **33,520** | **439,944** |

* The facility has proposed to limit the $NO_X$ emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

**Offset Calculations:**

$PM_{10}$:

SSPE2 ($PM_{10}$) = 161,545 lb/year
Offset threshold ($PM_{10}$) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|
| 33,087 | 33,086 | 33,086 | 33,086 |

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of $PM_{10}$ ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

| 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|
| 49,630 | 49,629 | 49,629 | 49,630 |

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in $PM_{10}$ emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| ERC #C-896-4 | 80 | 80 | 80 | 80 |
| ERC #N-721-4 | 0 | 0 | 3,215 | 0 |
| ERC #N-723-4 | 0 | 0 | 985 | 0 |
| ERC #S-2791-5 | 92,179 | 23,666 | 69,157 | 96,288 |
| ERC #S-2790-5 | 12,862 | 491 | 0 | 8,499 |
| ERC #S-2789-5 | 6 | 14 | 12 | 8 |
| ERC #S-2788-5 | 5 | 7 | 3 | 6 |
| ERC #N-762-5 | 21,000 | 21,000 | 21,000 | 21,000 |

Project $PM_{10}$ offset requirements

The applicant states either $PM_{10}$ ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the $PM_{10}$ offset requirements.

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| $PM_{10}$ Emissions to be offset: (at a 1.5:1 ratio): | 49,630 | 49,629 | 49,629 | 49,630 |
| Available ERCs from certificates C-896-4, N-721-4, and N-723-4: | 80 | 80 | 4,280 | 80 |
| ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4: | -80 | -80 | -4,280 | -80 |
| Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4: | 0 | 0 | 0 | 0 |
| Remaining $PM_{10}$ emissions to be offset (at a 1.5:1 ratio): | 49,550 | 49,549 | 45,349 | 49,550 |

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between $PM_{10}$ and $PM_{10}$ precursors (i.e. $SO_X$) may be allowed. The applicant is proposing to use interpollutant offsets $SO_X$ for $PM_{10}$ at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the $SO_X$ ERCs are being used to offset $PM_{10}$ emissions, the above applies to the $SO_X$ ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| Remaining $PM_{10}$ Emissions to be offset: (at a 1.5:1 ratio): | 49,550 | 49,549 | 45,349 | 49,550 |
| Remaining $PM_{10}$ emissions to be offset with $SO_X$ ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 49,550 | 49,549 | 45,349 | 49,550 |
| Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5: | 33,873 | 21,512 | 21,015 | 29,513 |
| Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5: | 0 | 0 | 0 | 0 |
| Remaining $PM_{10}$ emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |

| | 1st Quarter | 2nd Quarter | 3rd Quarter | 4th Quarter |
|---|---|---|---|---|
| Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |
| Remaining ERCs from certificate S-2791-5: | 92,179 | 23,666 | 69,157 | 96,288 |
| 1st qtr. ERCs applied to 2nd qtr. ERCs: | -4,371 | 4,371 | 0 | 0 |
| Adjusted Remaining ERCs from certificate S-2791-5: | 87,808 | 28,037 | 69,157 | 96,288 |
| Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant $SO_X$:$PM_{10}$ ratio): | 15,677 | 28,037 | 24,334 | 20,037 |
| ERCs applied from certificate S-2791-5 partially withdrawn: | 15,677 | 28,037 | 24,334 | 20,037 |
| Remaining ERCs from certificate S-2791-5: | 72,131 | 0 | 44,823 | 76,251 |

As seen above, the facility has sufficient credits to fully offset the quarterly $SO_X$ and $PM_{10}$ emissions increases associated with this project.

## V. Conclusion

Approve use of an overall $SO_X$ for $PM_{10}$ interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

## VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a $SO_X$ for $PM_{10}$ interpollutant offset ratio of 1.000:1.

## Appendix

A: District Review and Approval

# Appendix A

## District Review and Approval

# Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

# DEVELOPMENT OF THE INTERPOLLUTANT RATIO

## For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

## March 2009

# Introduction

**Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate**

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

# Analyses included in Interpollutant evaluation

### *Factors Considered*

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

### *Elements from 2008 PM 2.5 Plan*

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

### *Extension by additional analysis*

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

### *Strengths*

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

## *Limitations*

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

## Analyses contained in Receptor modeling

### *Factors Considered*

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

### *Analyses in receptor modeling that use input from regional modeling*

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

### *Extension by additional analysis*

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

### *Strengths*

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

### *Limitations*

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

## Analyses contained in Regional modeling

### *Factors Considered*

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

### *Extension by additional analysis*

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

### *Strengths*

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

### *Limitations*

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

## Results and Documentation

### SJVAPCD Interpollutant Ratio Results

**SOx for PM ratio: 1.000 ton of SOx per ton of PM**

**NOx for PM ratio: 2.629 tons of NOx per ton of PM**

**These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.**

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

# Interpollutant Ratio Issues & Documentation

| | TOPIC | Reference |
|---|---|---|
| 1 | **Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions. | 2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2 |
| 2 | **Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites. | *DV Qtrs* |
| 3 | **Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties. | *Q4 Model Pivot, Model-site chem, Model-Daily Q4* |
| 4 | **Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM. | 2008 PM2.5 Plan, Appendix F |
| | Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis. | 2008 PM2.5 Plan, Appendix G |
| 5 | **Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources. | 2008 PM2.5 Plan, Appendix F |
| 6 | **Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods. | 2008 PM2.5 Plan, Appendix G |
| 7 | **Common area of influence adjustments used for all receptor evaluations:**<br>Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2)<br>Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3)<br>Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2)<br>Marine emissions not found present in CMB modeling for this analysis. | Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets |
| 8 | **Variations to reflect secondary area of influence specific to location:**<br>Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources<br>Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources<br>Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2) | Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets |
| 9 | **Reasons for using 2009 Interpollutant Ratio Projection:**<br>2009 Interpollutant ratio is consistent with current emissions inventories | 2008 PM2.5 Plan |
| | Regional modeling does not show a significant change in chemical relationships through 2014. | *Q4 Model Pivot* |
| 10 | **Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets. | District Rule 2201 Section 4.13.3 |

# ATTACHMENT I

## _Additional Supplemental Information_

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

| Pollutant | Emission Factor (lb/MMBtu)[b] (fuel input) | Emission Factor Rating |
|---|---|---|
| Criteria Pollutants and Greenhouse Gases | | |
| $NO_x$[c] 90 - 105% Load | 4.08 E+00 | B |
| $NO_x$[c] <90% Load | 8.47 E-01 | B |
| CO[c] 90 - 105% Load | 3.17 E-01 | C |
| CO[c] <90% Load | 5.57 E-01 | B |
| $CO_2$[d] | 1.10 E+02 | A |
| $SO_2$[e] | 5.88 E-04 | A |
| TOC[f] | 1.47 E+00 | A |
| Methane[g] | 1.25 E+00 | C |
| VOC[h] | 1.18 E-01 | C |
| PM10 (filterable)[i] | 7.71 E-05 | D |
| PM2.5 (filterable)[i] | 7.71 E-05 | D |
| PM Condensable[j] | 9.91 E-03 | D |
| Trace Organic Compounds | | |
| 1,1,2,2-Tetrachloroethane[k] | <4.00 E-05 | E |
| 1,1,2-Trichloroethane[k] | <3.18 E-05 | E |
| 1,1-Dichloroethane | <2.36 E-05 | E |
| 1,2,3-Trimethylbenzene | 2.30 E-05 | D |
| 1,2,4-Trimethylbenzene | 1.43 E-05 | C |
| 1,2-Dichloroethane | <2.36 E-05 | E |
| 1,2-Dichloropropane | <2.69 E-05 | E |
| 1,3,5-Trimethylbenzene | 3.38 E-05 | D |
| 1,3-Butadiene[k] | 2.67E-04 | D |
| 1,3-Dichloropropene[k] | <2.64 E-05 | E |
| 2-Methylnaphthalene[k] | 3.32 E-05 | C |
| 2,2,4-Trimethylpentane[k] | 2.50 E-04 | C |
| Acenaphthene[k] | 1.25 E-06 | C |

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

| Pollutant | Emission Factor (lb/MMBtu)[b] (fuel input) | Emission Factor Rating |
|---|---|---|
| Criteria Pollutants and Greenhouse Gases | | |
| $NO_x$[c] 90 - 105% Load | 2.21 E+00 | A |
| $NO_x$[c] <90% Load | 2.27 E+00 | C |
| CO[c] 90 - 105% Load | 3.72 E+00 | A |
| CO[c] <90% Load | 3.51 E+00 | C |
| $CO_2$[d] | 1.10 E+02 | A |
| $SO_2$[e] | 5.88 E-04 | A |
| TOC[f] | 3.58 E-01 | C |
| Methane[g] | 2.30 E-01 | C |
| VOC[h] | 2.96 E-02 | C |
| PM10 (filterable)[i,j] | 9.50 E-03 | E |
| PM2.5 (filterable)[j] | 9.50 E-03 | E |
| PM Condensable[k] | 9.91 E-03 | E |
| Trace Organic Compounds | | |
| 1,1,2,2-Tetrachloroethane[l] | 2.53 E-05 | C |
| 1,1,2-Trichloroethane[l] | <1.53 E-05 | E |
| 1,1-Dichloroethane | <1.13 E-05 | E |
| 1,2-Dichloroethane | <1.13 E-05 | E |
| 1,2-Dichloropropane | <1.30 E-05 | E |
| 1,3-Butadiene[l] | 6.63 E-04 | D |
| 1,3-Dichloropropene[l] | <1.27 E-05 | E |
| Acetaldehyde[l,m] | 2.79 E-03 | C |
| Acrolein[l,m] | 2.63 E-03 | C |
| Benzene[l] | 1.58 E-03 | B |
| Butyr/isobutyraldehyde | 4.86 E-05 | D |
| Carbon Tetrachloride[l] | <1.77 E-05 | E |

| | SELECTION # |
|---|---|
| COAL (ANTHRACITE) | 0 |
| COAL (BITUMINOUS) | 1 |
| COAL (LIGNITE) | 2 |
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 3 |
| GAS (NATURAL) | 4 |
| GAS (PROPANE) | 5 |
| GAS (BUTANE) | 6 |
| WOOD | 7 |
| WOOD BARK | 8 |
| MUNICIPAL SOLID WASTE | 9 |

| STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3% | |
|---|---|
| Type of fuel (use table above) | 4 GAS |
| O2 correction (i.e., 3%) | 15 % |
| Enter LB/MMBTU emission factor | |
| NOx | 0.847 LB/MMBTU |
| CO | 0.130 LB/MMBTU |
| VOC (as methane) | 0.000 LB/MMBTU |

| CALCULATED EQUIVALENT CONCENTRATIONS | |
|---|---|
| NOx | 229.94 ppmv |
| CO | 57.98 ppmv |
| VOC (as methane) | 0.00 ppmv |

| pV = R*T | | |
|---|---|---|
| pressure (p) | 1 | atm |
| universal gas constant (R*) | 0.7302 | atm-scf/lbmole-oR |
| temperature (oF) | 60 | oF |
| calculated | | |
| molar specific volume (V) | 379.5 | scf/lbmole |
| Molecular weights | | |
| NOx | 46 | lb/lb-mole |
| CO | 28 | lb/lb-mole |
| VOC (as methane) | 16 | lb/lb-mole |

| F FACTORS FROM EPA METHOD 19 @ 68 F | | | |
|---|---|---|---|
| COAL (ANTHRACITE) | 10100 | DSCF/MMBTU | COAL |
| COAL (BITUMINOUS) | 9780 | DSCF/MMBTU | COAL |
| COAL (LIGNITE) | 9860 | DSCF/MMBTU | COAL |
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 9160 | DSCF/MMBTU | OIL |
| GAS (NATURAL) | 8710 | DSCF/MMBTU | GAS |
| GAS (PROPANE) | 8710 | DSCF/MMBTU | GAS |
| GAS (BUTANE) | 8710 | DSCF/MMBTU | GAS |
| WOOD | 9240 | DSCF/MMBTU | WOOD |
| WOOD BARK | 9600 | DSCF/MMBTU | WOOD BARK |
| MUNICIPAL SOLID WASTE | 9570 | DSCF/MMBTU | SOLID WASTE |
| F FACTOR USED IN CALCULATIONS | 8710 | DSCF/MMBTU | GAS |

# Parts Per Million Volume -> Grams/Brake Horsepower - Hour

## ppmv -> g/Bhp-hr

| Variables: | | |
|---|---|---|
| Engine Size: | 860 | hp |
| $NO_x$: | 230 | ppmv |
| CO: | 0 | ppmv |
| VOC: | 0 | ppmv (as $CH_4$) |
| $O_2$ level: | 15 | % |
| Engine Efficiency: | 35 | % (Assumed) |
| F-factor: | 8578 | dscf/MMBtu |
| Fuel Type | 1 | |

| | |
|---|---|
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 0 |
| GAS (NATURAL) | 1 |
| GAS (PROPANE) | 2 |
| GAS (BUTANE) | 3 |

| Given: | | |
|---|---|---|
| Conversion #1: | 379.5 | dscf/lb-mol |
| Conversion #2: | 393.236 | bhp-hr/MMBtu |
| Conversion #3: | 453.59 | g/lb |
| $MW_{(NOx)}$: | 46 | as $NO_2$ |
| $MW_{(CO)}$: | 28 | |
| $MW_{(VOC)}$: | 16 | as $CH_4$ |
| $O_2$ Correction: | 3.542 | |
| Pressure (p) | 1 | atm |
| Temp (°F) | 60 | °F |

## Formula:

$$\frac{\text{ppmv}}{1}\cdot\frac{\text{F-factor}}{1}\cdot\frac{MW_{pollutant}}{1}\cdot\frac{20.9}{(20.9 - O_2\%)}\cdot\frac{1}{\text{Conversion \#1}}\cdot\frac{1}{\text{Conversion \#2}}\cdot\frac{\text{Conversion \#3}}{1}\cdot\frac{1}{\text{Engine Eff.}} =$$

## for NO:

$$\frac{230\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9 - 15}\cdot\frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

## for CO:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9 - 15}\cdot\frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

## for VOC:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9 - 15}\cdot\frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

| | SELECTION # |
|---|---|
| COAL (ANTHRACITE) | 0 |
| COAL (BITUMINOUS) | 1 |
| COAL (LIGNITE) | 2 |
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 3 |
| GAS (NATURAL) | 4 |
| GAS (PROPANE) | 5 |
| GAS (BUTANE) | 6 |
| WOOD | 7 |
| WOOD BARK | 8 |
| MUNICIPAL SOLID WASTE | 9 |

| STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3% | |
|---|---|
| Type of fuel (use table above) | 4 GAS |
| O2 correction (i.e., 3%) | 15 % |
| Enter LB/MMBTU emission factor | |
| NOx | 2.270 LB/MMBTU |
| CO | 0.130 LB/MMBTU |
| VOC (as methane) | 0.000 LB/MMBTU |

| CALCULATED EQUIVALENT CONCENTRATIONS | |
|---|---|
| NOx | 616.25 ppmv |
| CO | 57.98 ppmv |
| VOC (as methane) | 0.00 ppmv |

| pV = R*T | | |
|---|---|---|
| pressure (p) | 1 | atm |
| universal gas constant (R*) | 0.7302 | atm-scf/lbmole-oR |
| temperature (oF) | 60 | oF |
| calculated | | |
| molar specific volume (V) | 379.5 | scf/lbmole |
| Molecular weights | | |
| NOx | 46 | lb/lb-mole |
| CO | 28 | lb/lb-mole |
| VOC (as methane) | 16 | lb/lb-mole |

| F FACTORS FROM EPA METHOD 19 @ 68 F | | |
|---|---|---|
| COAL (ANTHRACITE) | 10100 DSCF/MMBTU | COAL |
| COAL (BITUMINOUS) | 9780 DSCF/MMBTU | COAL |
| COAL (LIGNITE) | 9860 DSCF/MMBTU | COAL |
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 9160 DSCF/MMBTU | OIL |
| GAS (NATURAL) | 8710 DSCF/MMBTU | GAS |
| GAS (PROPANE) | 8710 DSCF/MMBTU | GAS |
| GAS (BUTANE) | 8710 DSCF/MMBTU | GAS |
| WOOD | 9240 DSCF/MMBTU | WOOD |
| WOOD BARK | 9600 DSCF/MMBTU | WOOD BARK |
| MUNICIPAL SOLID WASTE | 9570 DSCF/MMBTU | SOLID WASTE |
| F FACTOR USED IN CALCULATIONS | 8710 DSCF/MMBTU | GAS |

# Parts Per Million Volume —> Grams Brake Horsepower - Hour

## ppmv —> g/Bhp-hr

| Variables: | | |
|---|---|---|
| Engine Size: | 860 | hp |
| NOx: | 616 | ppmv |
| CO: | 0 | ppmv |
| VOC: | 0 | ppmv (as CH4) |
| $O_2$ level: | 15 | % |
| Engine Efficiency: | 35 | % (Assumed) |
| F-factor: | 8578 | dscf/MMBtu |
| Fuel Type | 1 | |

| | |
|---|---|
| OIL (CRUDE, RESIDUAL, OR DISTILLATE) | 0 |
| GAS (NATURAL) | 1 |
| GAS (PROPANE) | 2 |
| GAS (BUTANE) | 3 |

| Given: | | |
|---|---|---|
| Conversion #1: | 379.5 | dscf/lb-mol |
| Conversion #2: | 393.236 | bhp-hr/MMBtu |
| Conversion #3: | 453.59 | g/lb |
| MW (NOx): | 46 | as $NO_2$ |
| MW (CO): | 28 | |
| MW (VOC): | 16 | as $CH_4$ |
| $O_2$ Correction: | 3.542 | |
| Pressure (p) | 1 | atm |
| Temp (°F) | 60 | °F |

Formula:

$$\frac{\text{ppmv}}{1}\cdot\frac{\text{F-factor}}{1}\cdot\frac{MW_{pollutant}}{1}\cdot\frac{20.9}{(20.9-O_2\%)}\cdot\frac{1}{\text{Conversion \#1}}\cdot\frac{1}{\text{Conversion \#2}}\cdot\frac{\text{Conversion \#3}}{1}\cdot\frac{1}{\text{Engine Eff.}} =$$

for NOx:

$$\Rightarrow \frac{616\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9-15}\cdot\frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

$$\Rightarrow \frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9-15}\cdot\frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\Rightarrow \frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}}\cdot\frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}}\cdot\frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}}\cdot\frac{20.9}{20.9-15}\cdot\frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}}\cdot\frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}}\cdot\frac{453.59\ \text{g}}{\cancel{\text{lb}}}\cdot\frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

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JUL 0 3 2008
Permits Srvc
SJVAPCD

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

# ATTACHMENT J

## _EPA Comments and District Responses_

## EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

**EPA Comments – Letters Dated September 13, 2010**

**EPA Comment #1:**

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

**District's Response:**

*The permitted emissions from this facility are below PSD thresholds. The facility's $NO_X$ and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.*

*In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.*

**EPA Comment #2:**

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for $NO_X$, CO, VOC, $PM_{10}$, and $SO_X$ emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

**District's Response:**

*The potential emissions of $PM_{10}$ from the facility are 161,552 lb-$PM_{10}$/year (Calculated in the PDOC). Using the conservative assumption that all $PM_{10}$ is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.*

**EPA Comment #3:**

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) $NO_X$ and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of $NO_X$ emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of $NO_X$ and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the $NO_X$ permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

**District's Response:**

*Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.*

**EPA Comment #4:**

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the l-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's l-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

**<u>District's Response:</u>**

*a. The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).*

*b. The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's* *response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.*

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

**EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:**

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to <u>preconstruction</u> review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

*Guidance on Limiting Potential to Emit in New Source Permitting,* Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

**District's Response:**

*The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.*

*Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.*

# ATTACHMENT K

## *Green Action Comments and District Responses*

## Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

**Greenaction Comments – Letter Dated September 11, 2010**

**Greenaction Comment #1:**

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

**District's Response:**

*The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.*

*However, we went far beyond our required notification processes for this project, as follows:*

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

   *Bradley,*

   *The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm*

   *We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.*

   *I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.*

   *We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.*

> *Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.*
>
> *Dave Warner*
> *Director of Permit Services*
> *San Joaquin Valley APCD*

*In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.*

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an additional day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

*In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.*

**Greenaction Comment #2:**

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

**District's Response:**

*While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.*

**Greenaction Comment #3:**

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

**District's Response:**

*The District has searched the PDOC and has not been able to locate the phrase "zero impact".*

*However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.*

*The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for $NO_X$, CO, or $SO_X$. In addition, as shown in the PDOC, the calculated contribution of $PM_{10}$ will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.*

**<u>Greenaction Comment #4:</u>**

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

**<u>District's Response:</u>**

*The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.*

# ATTACHMENT L

## _NRDC and CRPE Comments and District Responses_

**National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response**

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

**NRDC and CRPE Comments – Letter Dated September 13, 2010**

**NRDC and CRPE Comment #1:**

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

**District's Response:**

*The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable $NO_X$ and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.*

**NRDC and CRPE Comment #2:**

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

**District's Response:**

*The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher $NO_X$ and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide $NO_X$ and CO emissions limits.*

*The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.*

*Attached Letter Addressed to U.S. EPA - Dated October 14, 2009*

**El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments**

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

**<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:</u>**

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

**<u>District's Response:</u>**

*This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.*

**<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:</u>**

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

**<u>District's Response:</u>**

*The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.*

*In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.*

*The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.*

**El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:**

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

**District's Response:**

*The facility is not using $PM_{10}$ as a surrogate for $PM_{2.5}$. The facility has proposed to offset $PM_{10}$ emissions with $SO_X$ ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The $SO_X$ for $PM_{10}$ offset ratio used in this project is based on the best available science for determining how much $PM_{10}$ $SO_X$ can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.*

**Attached Letter Addressed to U.S. EPA - Dated October 15, 2009**

**EarthJustice Comments**

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

**EarthJustice Comment #1:**

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

**District's Response:**

*This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.*

**EarthJustice Comment #2:**

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

**District's Response:**

*The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.*

*In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.*

*The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.*

**EarthJustice Comment #3:**

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

**District's Response:**

*The facility is not a Major Source for $PM_{2.5}$; therefore $PM_{2.5}$ (fine particulate matter) requirements will not be addressed in this project.*

*There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.*

# ATTACHMENT M

## *Rob Simpson Comments and District Responses*

## Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

**Rob Simpson Comments – Emailed Letters Received November 17, 2010**

**<u>Simpson Comment #1 - Public Notice:</u>**

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

**<u>District's Response:</u>**

*On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.*

**<u>Simpson Comment #2:</u>**

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> *"The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit."*

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

**District's Response:**

*See response to NRDC and CRPE comment #2.*

**Simpson Comment #3 - The District is the Lead Agency for this Project:**

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

**District's Response:**

*The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".*

**Simpson Comment #4 - Is an FDOC an ATC?:**

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

**District's Response:**

*The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.*

**Simpson Comment #5:**

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

**District's Response:**

*The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.*

**Simpson Comment #6:**

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

**District's Response:**

*Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.*

*Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.*

**Simpson Comment #7 - The BACT Analysis for the Permit is Defective:**

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing $NO_X$ emissions. (i.e. steam injection, dry low $NO_X$ combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of $NH_3$, and
- Evaluate $NH_3$ as a precursor to PM2.5.

**District's Response:**

*The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any $NO_X$ emissions control other than the use of SCR to lower the $NO_X$ emissions to 2.0 ppmvd @ 15% $O_2$, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for $NO_X$ as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15% $O_2$ as the most stringent technologically feasible $NO_X$ requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

*In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of $NH_3$ is not evaluated and can not be evaluated under the District's NSR rule.*

*The evaluation of $NH_3$ as a precursor to $PM_{2.5}$ was not performed since the facility is not a Major Source for $PM_{2.5}$ emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.*

**Simpson Comment #8 - $NO_X$ Emissions During Startup and Shut Down:**

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

**District's Response:**

*As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.*

**Simpson Comment #9 - BACT VOC Emission Limit:**

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

**District's Response:**

*As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% $O_2$ when the duct burner is fired, and 1.5 ppmvd @ 15% $O_2$ when the duct burner is not fired.*

*The applicant proposed VOC emissions of 1.4 ppmvd @ 15% $O_2$ when the unit is fired without the duct burner and 2.0 ppmvd @ 15% $O_2$ when it is fired with the duct* *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% $O_2$ did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% $O_2$ emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

**<u>Simpson Comment #10 - BACT $PM_{2.5}$ / $PM_{10}$ Emission Limit:</u>**

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

**<u>District's Response:</u>**

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for $PM_{10}$ as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

**<u>Simpson Comment #11 - Air Quality Impact Analysis:</u>**

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether 'the operation of the proposed equipment will cause or make worse a violation of an air quality standard. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the $98^{th}$ percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

**<u>District's Response:</u>**

*The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour* *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

**<u>Simpson Comment #12:</u>**

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

**<u>District's Response:</u>**

*The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.*

**<u>Simpson Comment #13 - Federal 1 hour NO2 Standard:</u>**

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

**<u>District's Response:</u>**

*This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.*

**<u>Simpson Comment #14:</u>**

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the $98^{th}$ percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

**District's Response:**

*The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

**Simpson Comment #15:**

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

**District's Response:**

*The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.*

**Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:**

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

**District's Response:**

*The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.*

**Simpson Comment #17 - Ammonia Emissions:**

Other power plant turbines have achieved a 2 ppm $NO_X$ limit with a 5 ppm $NH_3$ slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

**District's Response:**

*Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.*

*A high ammonia slip from the turbine will not lead to increased $PM_{10}$ formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on $NO_X$ reductions.*

*Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.*

**Simpson Comment #18 - Emission Reduction Credits:**

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

**District's Response:**

*The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.*

**Simpson Comment #19:**

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

**District's Response:**

*According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.*

**Simpson Comment #20:**

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

**District's Response:**

*Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.*

**Simpson Comment #21:**

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

**District's Response:**

*These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.*

**Simpson Comment #22:**

How much money does the District receive if this project is approved? Denied?

**District's Response:**

*Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.*

**Comments Received from Rob Simpson in Exhibit 4:**

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

**Simpson Comment #23:**

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

**District's Response:**

*The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.*

**Simpson Comment #24:**

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

**District's Response:**

*This comment was addressed in the District response to Rob Simpson Comment #17 above.*

**Comments Received from Rob Simpson in Exhibit 5:**

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).

# ATTACHMENT Q

| | NOx | SOx | PM10 | CO | VOC | PM2.5 | MW/hour | % of Avenal Electricity |
|---|---|---|---|---|---|---|---|---|
| **One Digester (lbs/year)** | 9,166 | 2,268 | 3,970 | 101,636 | 6,370 | 3970 | 1.059 | |
| **One Digester (tons/year)** | 4.58 | 1.13 | 1.99 | 50.82 | 3.19 | 1.99 | | |
| **25 Digesters (lbs/year)** | 229,150 | 56,700 | 99,250 | 2,540,900 | 159,250 | 99,250 | 26.475 | 4.41% |
| **25 Digesters (tons/year)** | 114.58 | 28.35 | 49.63 | 1,270.45 | 79.63 | 49.63 | | |
| **Avenal (lbs/year)** | 198,840 | 33,521 | 161,550 | 197,928 | 69,222 | 161550 | 600 | |
| **Avenal (tons/year)** | 99.42 | 16.76 | 80.78 | 98.96 | 34.61 | 80.775 | | |
| **Pollution Difference Digesters vs. Avenal (tons/year)** | 15.16 | 11.59 | -31.15 | 1,171.49 | 45.01 | -31.15 | | |

Source: Lakeview Dairy Biogas digester Authority to Construct Permit March 22, 2016, Post-Project Stationary Source Potential to Emit (SSPE2) at 14, 20

Source: Avenal Power Center Authority to Construct Permit No. December 17, 2010, Post-Project Stationary Source Potential to Emit (SSPE2) at 27.

# ATTACHMENT R

**BEFORE THE CALIFORNIA AIR RESOURCES BOARD**

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**PETITION FOR RECONSIDERATION OF THE DENIAL OF THE PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM**

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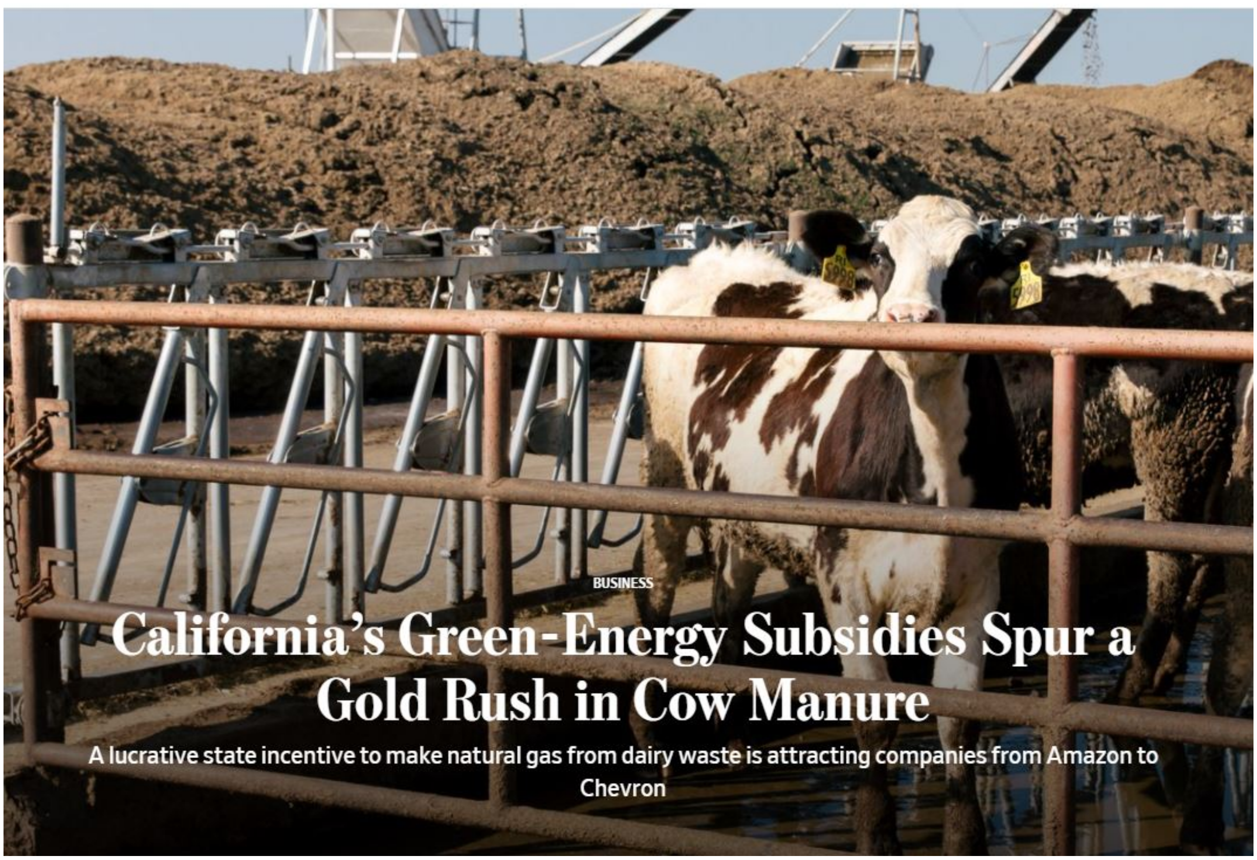
THE WALL STREET JOURNAL.



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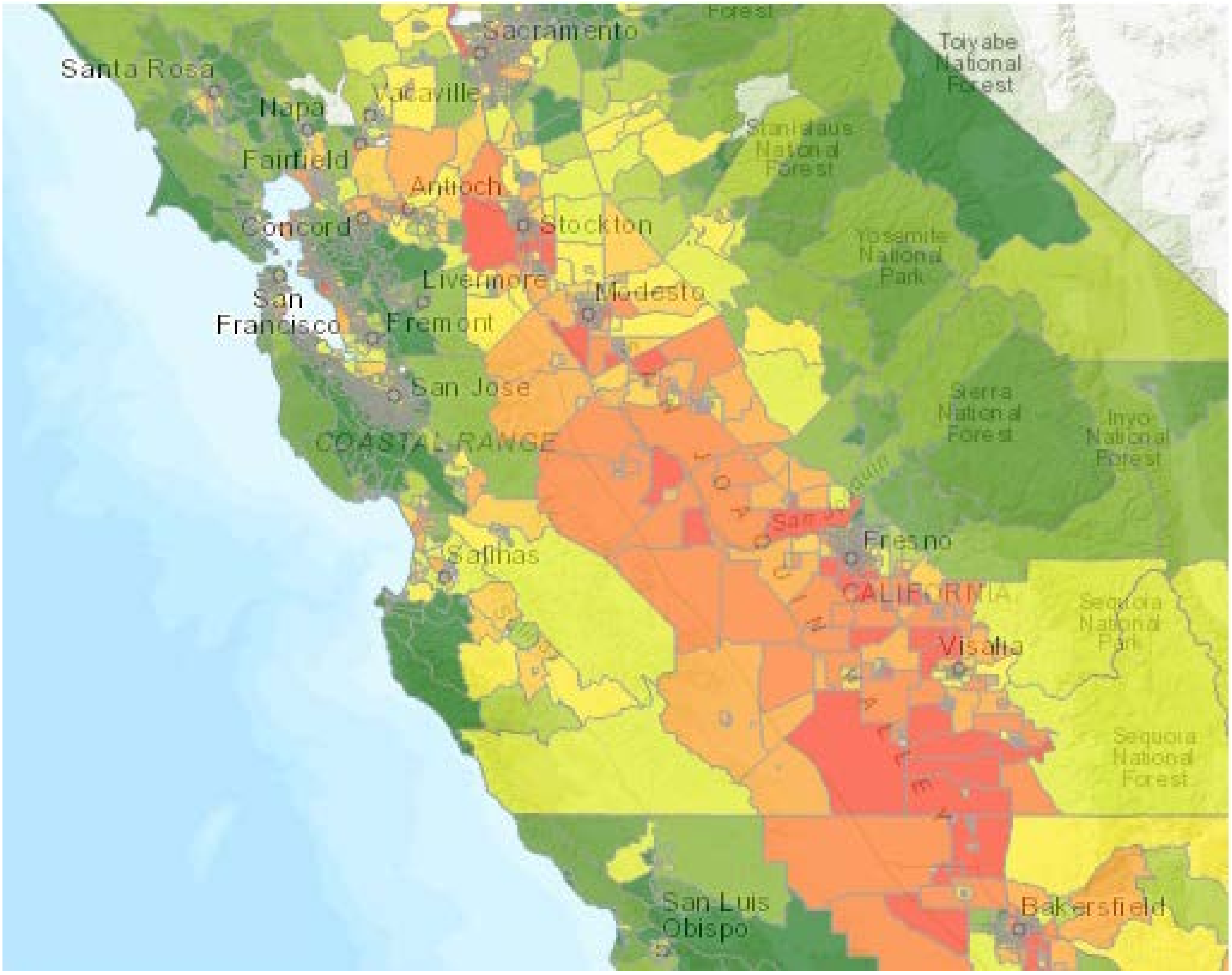
percent on high PM2.5 days.[119]

The "disadvantaged communities" of California, as defined pursuant to California Senate Bill 535, are concentrated in the San Joaquin Valley.[120] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[121] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[122] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687—both at 71 percent or below statewide median income.[123]

[119] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS 3-2 to 3-3 (Nov. 15 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.
[120] CALEPA, DESIGNATION OF DISADVANTAGED COMMUNITIES PURSUANT TO SENATE BILL 535 (DE LEÓN) 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf. All eight counties of the San Joaquin Valley exhibit the highest scores indicating the greatest pollution burden relative to the rest of California. *See Maps & Data*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Mar. 25, 2022) (flagging areas of California that exhibit high to low pollution burden scores); *see also infra* page 27, San Joaquin Valley CalEviroScreen 4.0 map.
[121] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. Attach. 10, *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); Attach. 11, *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.
[122] Attach. 12, *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Mar. 25, 2022).
[123] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced and Tulare facing 17 and 18.9 percent poverty rates, respectively (as compared to 11.8 percent at the statewide level). *Id.*

**San Joaquin Valley, CalEnviroScreen 4.0**




San Joaquin Valley residents are disproportionately Latino as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state, with populations ranging from 42 percent to 65.6 percent, as compared to the state population with 39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[124] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[125] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

[124] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*
[125] *Id.* at 114.

### i. Factory farm gas increases ammonia emissions.

Industrial dairies in the San Joaquin Valley are the largest source of ammonia.[126] Factory farm gas production adds even more ammonia to the air basin: one study documents that ammonia emissions from digestate increased 81% relative to raw manure.[127] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[128] Ammonia reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's PM2.5 pollution problem.[129]

CARB has analyzed the impact of ammonia emissions on ambient PM2.5 as part of the recent 2018 PM2.5 Plan for the Valley. CARB found that ammonia contributed 5.2 $\mu g/m^3$ to the ambient air and found that a 30 percent and 70 percent reduction in ammonia would result in a range of ambient reductions in PM2.5 from 0.08 to 2.3 $\mu g/m^3$.[130] For context, the 2012 annual PM2.5 standard is 12 $\mu g/m^3$.[131] The overall contribution of ammonia from current dairy activities would only increase as more anaerobic digesters cause an increase in ammoniacal nitrogen in the digestate and thus increase ammonia emitted into the air basin. This air pollution impact interferes with efforts to attain the PM2.5 24-hour and annual standards and causes a disparate impact on the basis of race and income. CARB cannot ignore this reality and must grant the Petition.

### ii. Factory farm gas electricity pathways increase ozone and PM2.5 precursors.

The Petition identifies the on-site combustion of factory farm gas using internal combustion engines to power turbines for electricity generation at dairy operations as a significant air quality impact in the San Joaquin Valley Air Basin.[132] This form of factory farm gas fuel pathway to generate LCFS credits produces negative CI fuel pathways designated for electric vehicles. For example, CARB certified a pathway for such fuel generated at the Hilarides Dairy for a -758.46 CI in B016301[133] and at the Bidart-Old River Dairy for a -558.62 CI in B005901.[134] To date, Petitioners have identified eight certified pathways generating electric vehicle fuel in factory farm gas-powered engines, all located in the San Joaquin Valley, and an

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[126] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[127] *See* Holly, et al., *supra* note 41.
[128] *Id.*
[129] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[130] SJVAPCD, 2018 PM2.5 PLAN, APPENDIX G, 3 and tables 2 through 7 (Oct. 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[131] *See* 78 Fed. Reg. 3086 (Jan. 15, 2013).
[132] Petition, *supra* note 1, at 30.
[133] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B016301 (certified June 21, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0163_cover.pdf.
[134] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B005901 (re-certified Mar. 25, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0059_cover.pdf.

additional number of similar facilities out of state.[135] Petitioners have further identified an additional three pending pathway certification applications, including one for the Lakeview Dairy.[136]

These fuel pathways represent a pollution-intensive form of fuel and one that rewards the developer with an extremely low CI value, creating an incentive to further develop this form of fuel pathway and thus even more air pollution in the Valley. To illustrate, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site and has applied for a fuel with a -382.98 CI value.[137] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5, and 3.18 tons/year of VOC after the imposition of Best Available Control Technology as required by the State Implementation Plan.[138] Compared to a natural gas combined cycle plant in Avenal also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[139] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted.[140] This facility *increases* air pollution in the San Joaquin Valley.

With eight certified pathways and at least three more pending, CARB will soon be allowing the functional equivalent of the Avenal Power Center operating at about 50 percent capacity and without having offset that pollution with emission reduction credits. Another dozen electric fuel pathways powered by factory farm gas-fueled engines at Valley dairies would emit the same amount of NOx pollution as Avenal at full capacity, but only generate 4.4 percent of the electricity.[141] A similar pattern results from the emissions of VOCs.[142] This absurdity is compounded by Air District offset thresholds such that the digester engines do not buy emissions offsets and thus add more air pollution to the air basin, while in theory the Avenal Power Center would have had to purchase offsets from other sources to achieve a no net increase. This occurs in one of the most polluted air basins in the United States and classified as nonattainment for several fine particulate matter National Ambient Air Quality Standards.[143] CARB has effectively allowed the LCFS to add more air pollution to the San Joaquin Valley, call it "renewable" fuel

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[135] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B001901, B003701, B008901, B005901, B016601, B003801, B002401, and B016301.
[136] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B0104, B0105, and B0106.
[137] SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0104 (certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
[138] SJVAPCD, *supra* note 137, at 14.
[139] Attach. 13, Digester v. Avenal Comparison; Attach. 14, SJVAPCD, NOTICE OF FINAL DETERMINATION OF COMPLIANCE, AVENAL POWER CENTER, 3, 27 (Dec. 17, 2010). Producing 1.059 megawatts and emitting 4.58 tons/year of NOx, the Lakeview turbine generates 0.17 percent of the electricity while the engines powering the turbine emit 4.6 percent of the NOx pollution.
[140] Attach. 15, SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT 14 (Mar. 22, 2016).
[141] Digester v. Avenal Comparison, *supra* note 139. This assumes that Lakeview represents the average emissions from these factory farm gas operations.
[142] *Id*.
[143] 80 Fed. Reg. 18,528 (April 7, 2015); 81 Fed. Reg. 84,481 (November 23, 2016); 80 Fed. Reg. 2,206, 2,217 (January 15, 2015).

for electric vehicles, and then allows credits from that fuel to be sold to fossil fuel deficit holders who then may increase the pollution from their fuels sold in California. By allowing polluting factory farm gas to generate credits for "renewable" electric vehicle fuel, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate that electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[144] CARB must also grant the Petition and ensure the LCFS-related air pollution does not inflict a disparate impact on the basis of race, and must ensure that the LCFS complies with AB 32, Government Code § 11135, and Title VI of the Civil Rights Act.

**d. Factory farm gas fuels consume significant energy inputs to produce which render factory farm gas much more pollution intensive than previously disclosed.**

As noted above, Petitioners have submitted comments on dozens of pathway certifications and consistently have objected to the heavy redaction of information as proprietary and confidential business information. Until recently, Petitioners have not seen some of the fuel inputs for factory farm gas development as a result of this heavy-handed redaction. But recently, fuel pathway applications from Wisconsin-based factory farm gas operators shed much-needed transparency on the energy-intensive generation of factory farm gas. CARB should grant the Petition and, because such information was unavailable at the time of the Petition, also consider and disclose net energy consumption when calculating the CI values for factory farm-gas derived fuels.

First, the significance of the redactions to date have rendered meaningful public review of fuel consumption and energy inputs impossible. Below is an example of an application from a Sacramento-area factory farm gas project which claimed one of the largest negative CIs.[145]

[144] § 38562(b).
[145] SMUD, NEW HOPE DAIRY DIGESTER GREET LCFS PATHWAY TO PRODUCE ELECTRICITY TO CHARGE ELECTRIC VEHICLES IN SMUD REGION & CALIFORNIA (Dec. 4, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0166_1_report.pdf.

Sacramento 1500 Cow dairy 06/03/2021

**4. Life Cycle Results for Carbon Intensity**

The calculated Carbon Intensity for New Hope dairy digester system to charge electric vehicles = **-750.81 $gCO_{2e}$/MJ**, see table below.

[redacted]

Page | 8 New Hope Dairy Digester to EV Pathway Application No. B0166 Facility ID: F00255 Copyright © 2020

Still other pathway applications fully redact all input data and only disclose the final CI. This CI calculation from the Western Sky Dairy in Kern County illustrates this degree of redaction.[146]

**Exhibit 25. Total Carbon Intensity for Dairy Manure Pathway-Western Sky Biogas LLC**

| Process Stage | Carbon Intensity ($gCO_2e$/MJ Biogas) |
|---|---|
| Diesel Consumption | [redacted] |
| Electricity Consumption | [redacted] |
| Loss/Fugitives | [redacted] |
| Biomethane Transmission | [redacted] |
| Compression of CNG | [redacted] |
| Tailpipe Emissions | [redacted] |
| Methane Avoided | [redacted] |
| $CO_2$ Diverted | [redacted] |
| Final CNG CI ($gCO_2e$/MJ) | -385.40 |

09/30/2021 Kern County, CA

[146] CALIFORNIA BIOENERGY, LIFE-CYCLE ASSESSMENT OF DAIRY MANURE BIOGAS TO CNG (Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_report.pdf. Also noteworthy is the fact that Western Sky Dairy is one of the eight dairies generating reductions credited towards the DDRDP, the Aliso Canyon Mitigation Agreement, and the LCFS.

# ATTACHMENT S

# Ammonia: Supplemental Information for EPA in Support of 15 µg/m3 Annual PM2.5 Standard

*March 2023*

# Table of Contents

## Executive Summary

The California Air Resources Board (CARB) and San Joaquin Valley Air Pollution Control District (District) are providing this information at the request of United States Environmental Protection Agency (EPA) staff to further clarify the assessment of ammonia as a precursor to fine particulate matter (PM2.5) in the San Joaquin Valley (Valley). Specifically, this supplemental information summarizes previous information submitted to EPA and also provides new information intended to support EPA action on the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 µg/m3 SIP Revision) submitted to EPA in 2021.

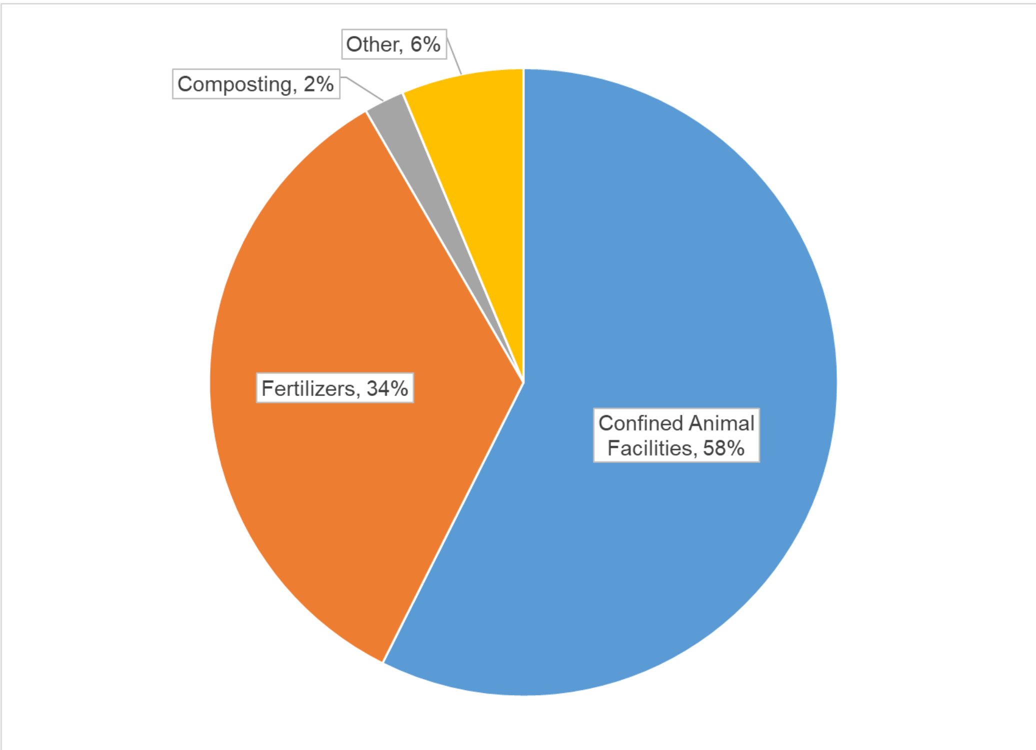
This document summarizes and reinforces the findings on ammonia as a precursor previously submitted to EPA in four documents provided between 2019 and 2021. CARB and the District continue to assert that, as documented in previous submittals, ammonia is not a significant attainment precursor for PM2.5 in the Valley for the 15 microgram per cubic meter (µg/m3) annual PM2.5 standard. PM2.5 is a complex mixture of many chemical species. Roughly 40 percent of PM2.5 is made up of ammonium nitrate particulate which is itself a combination of two precursors, ammonia and oxides of nitrogen (NOx). NOx emissions in the Valley come primarily from mobile sources while ammonia emissions come primarily from area sources. Ammonium nitrate reductions are critical for the Valley to attain the 15 ug/m3 annual PM2.5 air quality standards and provide cleaner air to residents. Ammonium nitrate formation is limited by the precursor, either ammonia or NOx, in least supply. Due to these complex reactions, when a pollutant is abundant, controlling that pollutant may not lead to PM2.5 air quality improvement. In other words, in order to reduce a secondary pollutant like ammonium nitrate PM2.5, controls need to target the pollutant that limits the chemical reaction.

Multiple field studies in the Valley have confirmed that NOx is the limiting precursor to ammonium nitrate formation and that there is a far greater amount of ammonia in the Valley's air than is necessary to participate in the chemistry that leads to ammonium nitrate. Thus, NOx reductions are key for reducing ammonium nitrate and PM2.5 levels in the Valley. The attainment strategy recognizes this scientific finding and calls for significant NOx reductions, primarily achieved through CARB's mobile source control measures. Air quality modeling also shows that the effectiveness of ammonia controls will rapidly decrease through the 2023 timeframe as the Valley's air becomes even more NOx-limited due to dramatic and ongoing reductions in NOx from these mobile source control measures.

EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, 0.25 µg/m3 for the 15.0 µg/m3 annual PM2.5 standard. At a 30 percent reduction in ammonia emissions, one site, Hanford, exceeded the 0.25 µg/m3 threshold with a value of 0.26 µg/m3. Further, nationwide, ammonia emissions are flat indicating that the sources are not being controlled significantly.

Per EPA's request, the District and CARB analyzed potential control measures to reduce ammonia emissions to evaluate whether a 30 percent reduction in emissions is feasible. Thus, negating consideration of the 70 percent precursor evaluation. For an effective control measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley. The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions as shown below in Figure ES-1, are the focus of the evaluation. These are confined animal facilities (contributing 186.5 tons per day (tpd) of ammonia emissions in 2023), agricultural fertilizers (111.2 tpd), and composting of solid and biological waste (6.7 tpd)[1].

**Figure ES-1: Sources of Ammonia in the San Joaquin Valley**




Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions for this submittal for the15 µg/m3 SIP Revision. EPA provided the list of measures to CARB and the District, and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. Through this

[1] 15 µg/m3 SIP Revision

evaluation, the District identified a total of 6.6 tpd of ammonia emission reductions from confined animal facilities.

For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules regulating fertilizer application. Nor has EPA staff identified any rules applicable to regulating air emissions from non-organic fertilizer application. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources. Based on this extensive evaluation, identified feasible controls, as summarized below in Table ES-1, can reduce ammonia emissions by approximately 2 percent. Therefore, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

**Table ES-1. Estimated Feasible Ammonia Emission Reductions**

| Emissions Category | Emissions (tpd, 2023) | Identified Controls | Feasible Ammonia Reductions |
|---|---|---|---|
| Confined Animal Feeding | 186.5 | • Reducing crude protein content in feed for beef finishing cattle<br>• Incorporation of solid manure within 24 hours<br>• Acidifying amendments for poultry litter and manure | 6.6 tpd |
| Fertilizers | 111.2 | No authority or feasible controls identified | 0 |
| Composting | 6.7 | No additional feasible controls identified at this time | 0 |
| Other sources | 20.5 | No feasible controls identified | 0 |
| Total Ammonia | 324.9 | | 6.6 tpd |

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. While a precursor sensitivity analysis showed a small impact when ammonia was reduced by 30 percent, achieving this level of control in practice is infeasible. Thus, considering relevant contextualizing information including available controls, CARB determined that ammonia emission reductions do not improve PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia as an attainment precursor and from control requirements in the SIP.

## 1. Background

PM2.5 is made up of many constituent particles that are either directly emitted, such as soot and dust, or formed through complex reactions of gases in the atmosphere. NOx, sulfur dioxide (SO2), volatile organic compounds (VOCs), and ammonia are gases that are precursors to PM2.5, transforming into particles through physical and chemical atmospheric processes.

Ammonium nitrate (NH4NO3) is a constituent of PM2.5, making up about 40 percent of PM2.5 mass in the Valley. Ammonium nitrate forms when nitrogen dioxide (NO2) reacts with highly oxidizing species in the atmosphere to form nitric acid (HNO3). Nitric acid then reacts with ammonia (NH3) to yield ammonium nitrate as a particle. Since ammonia reacts chemically in this way to form a particle, ammonia is a precursor to PM2.5.

Lowering PM2.5 concentrations to levels that meet the 15 µg/m3 annual PM2.5 standard will rely upon an effective control strategy for ammonium nitrate. The amount of ammonium nitrate that can form in the atmosphere is limited by whichever precursor, either NOx or ammonia, is in least supply, and research studies confirm that there are relatively fewer NOx molecules in the air in the Valley than ammonia. This implies that reducing NOx, the limiting precursor in this case, is more effective for reducing ammonium nitrate concentrations and thus improving PM2.5 air quality.

The 2018 PM2.5 Plan was developed jointly by CARB and the District to address four PM2.5 federal ambient air quality standards: the 15 µg/m3 annual, 65 µg/m3 24-hour, 35 µg/m3 24-hour, and 12 µg/m3 annual standards. For the 15 µg/m3 annual standard, the 2018 PM2.5 Plan established 2020 as the attainment date. In 2020, one air monitoring site—Bakersfield-Planz—recorded a design value over the standard despite excluding the impacts of wildfires. Since the 2020 attainment date was no longer approvable, EPA proposed, on July 22, 2021, to partially approve and partially disapprove the portions of the 2018 PM2.5 Plan pertaining to the 15 µg/m3 annual standard.[2] Specifically, EPA proposed to disapprove the following SIP elements related to the attainment demonstration for the 15 µg/m3 standard: the precursor demonstration (including for ammonia), BACM/BACT demonstration, five percent demonstration, attainment demonstration, reasonable further progress demonstration, quantitative milestone demonstration, motor vehicle emissions budgets, and contingency measure. EPA proposed to approve the 2013 base year emissions inventories.[3]

[2] 86 FR 38652. EPA's final disapproval published November 26, 2021 (86 FR 67329)

[3] The 2018 PM2.5 Plan used CEPAM 2016 version 1.05. Any new analysis in this supplemental document uses the same version of the emissions inventory.

The District and CARB quickly revised the 2018 PM2.5 SIP to address the disapproval and demonstrate attainment of the 15 µg/m3 annual PM2.5 standard as soon as possible. Accordingly, the agencies worked together to develop the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 µg/m3 SIP Revision). The 15 µg/m3 SIP Revision amends the 2018 PM2.5 Plan to update the SIP elements associated with the disapproved attainment demonstration and demonstrates that the Valley will meet the 15 µg/m3 annual PM2.5 standard in 2023, including at the high site of Bakersfield-Planz with a 2023 design value (DV) of 14.7 µg/m3.

The 15 µg/m3 SIP Revision satisfies statutory requirements for a Clean Air Act §189(d) plan for a Serious nonattainment area SIP submission. The Valley is able to demonstrate attainment with reductions in emissions of NOx and PM2.5 coming from (1) ongoing implementation of CARB and the District's existing control strategy, (2) newly adopted CARB and District measures providing near-term reductions, and (3) a CARB aggregate emission reduction commitment made for the 15 µg/m3 SIP Revision for reductions in 2023 from measures in the 2018 PM2.5 Plan. Similar to the precursor demonstration for the 12 µg/m3 annual standard which projected attainment in 2025 and relied upon the 35 µg/m3 24-hour 2024 precursor demonstration, the 15 µg/m3 SIP Revision also relies on the EPA approved.[4] precursor demonstration associated with the 35 µg/m3 24-hour PM2.5 standard. Both are within one year of the 35 µg/m3 24-hour PM2.5 standard attainment deadline and precursor sensitivities can be assumed to be very similar to those modeled in 2024 The District Governing Board adopted the 15 µg/m3 SIP Revision on August 19, 2021, and the CARB Board adopted it on September 23, 2021. Subsequently, CARB submitted the adopted 15 µg/m3 SIP Revision to EPA as a revision to the California SIP on November 8, 2021.

CARB has provided supplemental information on ammonia to EPA on four previous occasions, as outlined below in Table 1. This supplemental document summarizes findings and information in those previous submittals, and also provides new, extensive evaluation. It is provided in support of EPA action on the 15 µg/m3 SIP Revision.

[4] See also "Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS," February 2020.

**Table 1. Previous Submittals to EPA of Supplemental Information on Ammonia**

| Document | Date Provided to EPA | Delivery Method(s) | Key Points |
|---|---|---|---|
| **Appendix G 2018 PM2.5 Plan** | January 2019 | The precursor analysis required for the SIP by the CAA | • Includes sensitivity analyses showing that 30% reduction of ammonia in the SIP base year of 2013 would have PM2.5 benefit, but in future years as the Valley becomes more NOx-limited, ammonia reductions would not have PM2.5 benefit<br>• Considering relevant contextualizing information such as emissions trends, research, and available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the PM2.5 standards in SJV, and therefore excluded ammonia from control requirements in the SIP. |
| **Submittal letter with attachment** | May 2019 | Provided as attachment to letter submitting the comprehensive 2018 PM2.5 SIP to EPA | • Cites studies showing ammonia is in excess of NOx in the Valley, making NOx the limiting precursor to control for PM2.5 benefits<br>• Indicates that the Valley will only become more NOx-limited in future years as NOx continues to decrease and ammonia levels remain stable<br>• Highlights CARB research efforts on ammonia |
| **Clarifying Information on Ammonia** | October 2019 | Emailed directly to EPA staff | • Explains that 30% ammonia reduction is infeasible, points out that fertilizer (a major ammonia source in SJV) is not within CARB's authority to control<br>• Explains that SJVAPCD is already implementing BACT for ammonia<br>• Summarizes ammonia-related research at CARB |
| **Ammonia Update 2017 Data for EPA** | September 2021 | Emailed directly to EPA staff and published as attachment to staff report for Board item related to SJV PM2.5 | • Provides new data from a 2017 study in the Valley supporting our previous findings that ammonia is not a significant precursor |

# 2. Precursor Demonstration

EPA finalized a PM2.5 SIP Requirements Rule[5] (Rule) that identifies the four PM2.5 precursor pollutants—NOx, $SO_2$, VOCs, and ammonia—that "must be evaluated for potential control measures in any $PM_{2.5}$ attainment plan."[6] The Rule permits air agencies to "submit an optional precursor demonstration designed to show that for a specific PM2.5 nonattainment area, emissions of a particular precursor from sources within the nonattainment area do not or would not contribute significantly to PM2.5 levels that exceed" the National Ambient Air Quality Standards (NAAQS).[7] If the agency's demonstration is approved by EPA, the attainment plan "may exclude that precursor from certain control requirements under the Clean Air Act."[8]

In Appendix G to the 2018 PM2.5 Plan, CARB included precursor demonstrations for three PM2.5 precursors, including ammonia. Following EPA guidance, the ammonia precursor demonstration analyzed "the relationship between precursor emissions and the formation of secondary PM2.5 components"[9] using an air quality model, and take into consideration additional relevant factors.

## EPA PM2.5 Precursor Demonstration Guidance

In November 2016, EPA published a draft guidance document to "assist air agencies who may wish to submit PM2.5 precursor demonstrations."[10] The document provides recommendations or guidelines, as authorized under the Clean Air Act, "that will be useful to air agencies in developing the precursor demonstrations by which the EPA can ultimately determine whether sources of a particular precursor contribute significantly to PM2.5 levels that exceed the standard in a particular nonattainment area."[11] Recommendations include modeling procedures for conducting the required analysis and contribution thresholds to determine the impact of a precursor on PM2.5 levels.[12] The guidance also describes an analytical process to perform the precursor demonstration, involving (1) a concentration-based analysis followed by (2) a sensitivity-based analysis and (3) consideration of additional information including what is achievable through controls.

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[5] 81 FR 58010 (August 24, 2016)

[6] EPA. *PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment*. 17 Nov. 2016. Web. 3 Oct. 2017. <www.epa.gov/sites/production/files/2016-11/documents/transmittal_memo_and_draft_pm25_precursor_demo_guidance_11_17_16.pdf>. Page 7

[7] Ibid. 7

[8] Ibid. 7

[9] Ibid. 26

[10] Ibid. 7

[11] Ibid. 7-8

[12] Ibid. 9

## Concentration-Based Analysis

The evaluation of precursors begins with a concentration-based analysis using ambient data to determine whether precursor emissions contribute to total PM2.5 concentrations.[13] Each precursor's impact on total $PM_{2.5}$ mass is compared to contribution thresholds. EPA recommends values for these thresholds, or air quality concentrations below which air quality impacts are not statistically significantly different from "the inherent variability in the measured atmospheric conditions," and thus do not contribute to PM2.5 concentrations that exceed the NAAQS.[14] The threshold given in the guidance document is 0.2 µg/m3 for the annual PM2.5 standard.[15] This threshold was calculated based on EPA's guidance for the 12 µg/m3 annual NAAQS. If adjusted to reflect the 15 µg/m3 annual standard, the 0.2 µg/m3 threshold for the 12 µg/m3 annual PM2.5 standard increases to 0.25 µg/m3 for the 15 µg/m3 annual PM2.5 standard. As shown below in Table 2, based on this metric, ammonia contributes to total PM2.5 mass in the Valley in amounts that exceed EPA's recommended thresholds.

**Table 2. Contribution of Ammonia to Total PM2.5 Mass**

| Species | Precursor | Species Contribution (ug/m3) to PM2.5 Mass* | Over Threshold? |
|---|---|---|---|
| **Ammonium nitrate** | Ammonia | 5.2 | Yes |

* 2015 annual average for Bakersfield

This concentration-based analysis, however, does not accurately capture the impact of reductions of precursor emissions on PM2.5 levels. Since the concentration-based analysis shows the precursors contribute to total PM2.5 mass in amounts over EPA's recommended thresholds, CARB proceeded to conduct an optional sensitivity-based analysis to demonstrate that reductions of ammonia will have a negligible impact on PM2.5.

## Sensitivity-Based Analysis

The SIP Requirements Rule allows for a sensitivity-based analysis to examine the degree to which PM2.5 levels are sensitive to precursor reductions. According to the guidance:

> This modeling analysis examines the sensitivity of ambient $PM_{2.5}$ concentrations in the nonattainment area to certain amounts of decreases in the precursor emissions in the area…. Where decreases in emissions of the precursor result in negligible air quality impacts (i.e., the area is "not sensitive" to decreases), such a small degree of impact is

[13] Ibid. 8
[14] Ibid. 14, 15
[15] Ibid. 15-16

not significant and can be considered to not "contribute" to PM2.5 concentrations for the purposes of determining whether control requirements should apply.[16]

Generally, EPA recommends that the precursor demonstration "should be based on current conditions to demonstrate that precursor emissions do not contribute significantly to $PM_{2.5}$ concentrations in the nonattainment area."[17] This means evaluating emissions in a selected base year, which may be the present or a previous year.

For each existing PM2.5 monitor location in the area,[18] the first step for estimating PM2.5 impacts from ammonia in the base year is to estimate the average PM2.5 concentration on an annual basis. The second step is to calculate the annual average PM2.5 concentration at each monitor with a specified percent reduction in precursor emissions, still in the base year.[19] The difference between these two calculated PM2.5 values is the impact on PM2.5 levels from precursor emissions reductions.[20] Note that "precursor demonstrations do not examine changes in emissions *between a base year and a future year*. Instead, the calculation of relative changes in $PM_{2.5}$ concentrations occur *between a modeled case with all emissions and a modeled case with reduced precursor emissions*" (emphasis added).[21] In addition, EPA recommends modeling reductions of between 30 and 70 percent of precursor emissions.[22]

EPA guidance recommends a range of 30 to 70 percent since emission reductions need to be large enough to test the interaction of the precursor. In general, the recommended range is reasonable for NOx and SO2, this range is not reasonable for ammonia. As indicated in the EPA guidance, between 2011 and 2017, the median change in SO2 and NOx emissions was -63.6 and -31.8 percent, while the median change in ammonia was a positive 0.8 percent. The large reductions in NOx and SO2 emissions are in response to reasonable controls that are available and in practice at sources. The slight increase nationally of ammonia is indicative of the lack of controls on ammonia sources across the nation. While new types of controls are being developed for ammonia, the availability and magnitude of ammonia controls that meet EPA's requirements for submittal into the SIP along with ammonia emission reductions trends support that the 30 percent reduction may not be reasonable.

The third step in the sensitivity-based analysis is to compare the modeled impact on PM2.5 levels from a decrease in ammonia emissions to contribution thresholds for annual average PM2.5. Following the analytical process outlined in the EPA precursor demonstration guidance and summarized above, CARB has evaluated ammonia in the Valley. The results of the sensitivity-based analysis and consideration of additional information are presented below.

[16] Ibid. 25
[17] Ibid. 33
[18] Ibid. 16
[19] Ibid. 36
[20] Ibid. 36
[21] Ibid. 34
[22] Ibid. 29

CARB staff used an air quality model to estimate the PM2.5 design value for the annual standard in the base year of 2013 at each Valley monitor. Then, CARB staff applied the recommended lower bound of a 30 percent reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in 2013. This is the value that is compared to EPA's adjusted contribution threshold for the 15 µg/m3 annual standard of 0.25 µg/m3 to establish if PM2.5 levels are sensitive to this level of ammonia reduction. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in the base year. The results are shown in Table 3.

**Table 3. Base Year 2013 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions**

| Site | 2013 Baseline DV | 2013 DV with 30% Ammonia Reduction | Difference | 2013 DV with 70% Ammonia Reduction | Difference |
|---|---|---|---|---|---|
| **Bakersfield-Planz** | 17.19 | 16.76 | 0.43 | 15.72 | 1.47 |
| **Madera** | 16.93 | 16.29 | 0.64 | 14.81 | 2.12 |
| **Hanford** | 16.54 | 15.82 | 0.72 | 14.24 | 2.30 |
| **Visalia** | 16.20 | 15.82 | 0.38 | 14.80 | 1.40 |
| **Clovis** | 16.12 | 15.80 | 0.32 | 14.95 | 1.17 |
| **Bakersfield-California** | 16.02 | 15.58 | 0.44 | 14.47 | 1.55 |
| **Fresno-Garland** | 14.98 | 14.69 | 0.29 | 13.91 | 1.07 |
| **Turlock** | 14.88 | 14.46 | 0.42 | 13.46 | 1.42 |
| **Fresno-HW** | 14.22 | 13.95 | 0.27 | 13.17 | 1.05 |
| **Stockton** | 13.14 | 12.84 | 0.30 | 12.10 | 1.04 |
| **Merced-S Coffee** | 13.10 | 12.65 | 0.45 | 11.60 | 1.50 |
| **Modesto** | 13.03 | 12.66 | 0.37 | 11.78 | 1.25 |
| **Merced-M** | 10.97 | 10.77 | 0.20 | 10.23 | 0.74 |
| **Manteca** | 10.09 | 9.85 | 0.24 | 9.27 | 0.82 |
| **Tranquility** | 7.72 | 7.33 | 0.39 | 6.46 | 1.26 |

From this analysis, the estimated air quality impact of reducing ammonia emissions by the lower bound of 30 percent in the base year exceeds EPA's adjusted annual threshold of 0.25 µg/m3 at all but two Valley monitors for the SIP base emission inventory year, 2013, 10 years ago. Reducing emissions by the upper bound of 70 percent also shows impacts above the threshold for this time period.

It is not possible, however, to conclude from this analysis that emissions of ammonia contribute significantly to PM2.5 levels. In this case, ammonia emissions have an impact above the recommended contribution threshold even at the lower bound of 30 percent emission reduction, but this does not necessarily mean the precursor contributes significantly to PM2.5 levels that exceed the NAAQS. Making the appropriate determination about the ammonia emission reduction impact requires further analysis of additional factors, such as future emission controls and potential controls on the precursors as allowed per the EPA guidance.

## Consideration of Additional Information

To supplement modeling analysis, EPA guidance also allows an air agency to consider additional information, assessing the significance of a precursor "'based on the facts and circumstances of the area.'"[23] The guidance states:

> If the estimated air quality impact exceeds the recommended contribution thresholds…, this fact does not necessarily preclude approval of the precursor demonstration. There may be cases where it could be determined that precursor emissions have an impact above the recommended contribution thresholds, yet do not "significantly contribute" to levels that exceed the standard in the area.[24]

In these cases, an air agency may "provide EPA with information related to other factors they believe should be considered in determining whether the contribution of emissions of a particular precursor to levels that exceed the NAAQS is 'significant' or not."[25] Such factors may include: trends in emissions of other precursors such as NOx,[26] anticipated growth or loss of emissions sources,[27] and the consequent appropriateness of modeling impacts in a future year instead of a base year;[28] "available emissions controls,"[29] and "the severity of nonattainment at relevant monitors."[30] Other factors the agency may consider are: the amount by which a precursor's contribution exceeds the recommended contribution thresholds; source characteristics (e.g., source type, stack height, location); analyses of speciation data and precursor emission inventories; chemical tracer studies; and special

[23] Ibid. 17
[24] Ibid. 17
[25] Ibid. 17
[26] Ibid. 17
[27] Ibid. 17
[28] Ibid. 33
[29] Ibid. 29
[30] Ibid. 17

intensive measurement studies to evaluate specific atmospheric chemistry in an area. The agency may also provide other information not listed here.[31]

CARB and the District conducted additional analysis related to these factors in accordance with EPA guidance to provide information related to other factors beyond the concentration- and sensitivity-based analyses that should be considered in determining whether the contribution of ammonia emissions to levels that exceed the 15 µg/m3 annual PM2.5 is "significant" or not. These analyses are described below.

### Emissions Trends and Studies

CARB has an extensive suite of measures in place to reduce NOx emissions from mobile sources that reduce ammonium nitrate. Between 2013 and 2024, total NOx emissions are projected to decline 53 percent. Meanwhile, total ammonia emissions are expected to remain flat, as shown in Figure 1. The District adopted four rules[32] between 2004 and 2011 with measures that provided ammonia emissions reductions in the Valley; however, reductions from these existing control measures are already accounted for in the inventory, prior to the 2018 PM2.5 SIP base year of 2013. In the future, emissions from the main sources of ammonia—dairies, fertilizer, and non-dairy livestock operations—are not anticipated to either increase or decrease substantially.

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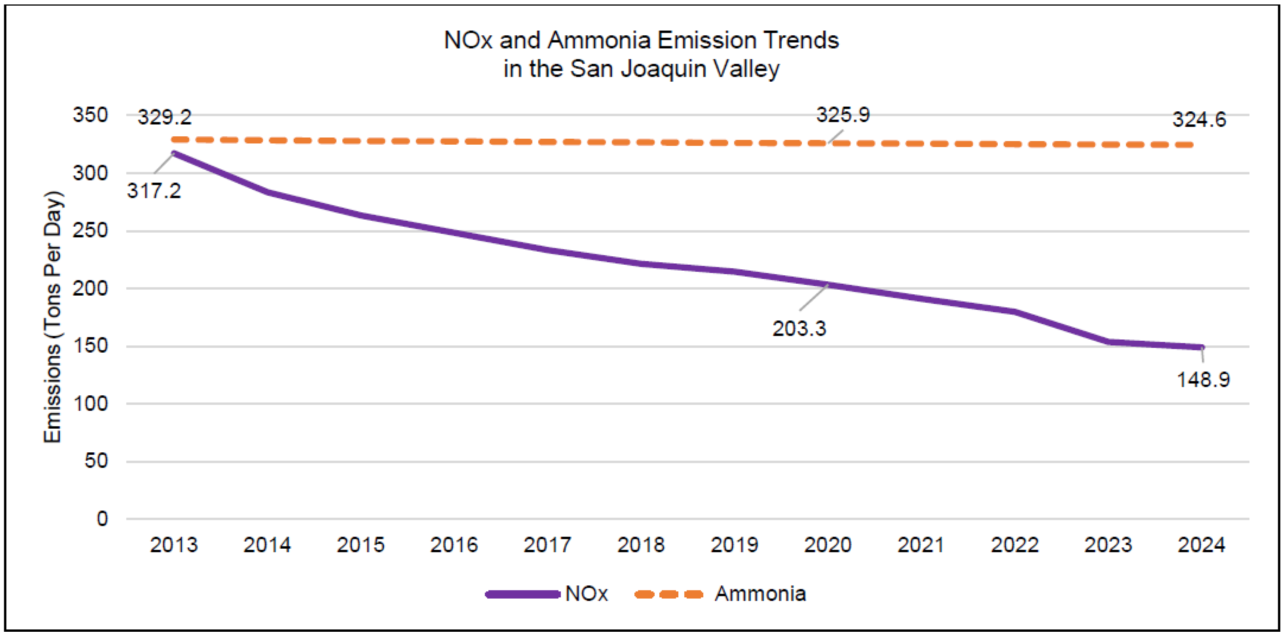
[31] Ibid. 17

[32] District Rule 4550: Conservation Management Practices (adopted 2004); Rule 4565: Biosolids, Animal Manure, and Poultry Litter Operations (adopted 2007); Rule 4566: Organic Material Composting Operations (adopted 2011); and Rule 4570: Confined Animal Facilities (adopted 2006, amended 2010)

**Figure 1. NOx and ammonia emission trends in the San Joaquin Valley between 2013 and 2024**




Source: CEPAM 2016 v 1.05

The steep downward trend of NOx emissions and the stability of ammonia emissions between 2013 and 2024 along with the time that has passed since 2013, lead CARB staff to conclude that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. EPA guidance states that, in some situations, it may be "more appropriate to model future conditions that provide a more representative sensitivity analysis."[33] This approach is applicable in the Valley. Although emissions of NOx and ammonia are of roughly similar magnitude in the base year, thereby leading to some modeled sensitivity of PM2.5 levels to a 30 percent reduction in ammonia emissions, these conditions do not persist and are not representative in the future.

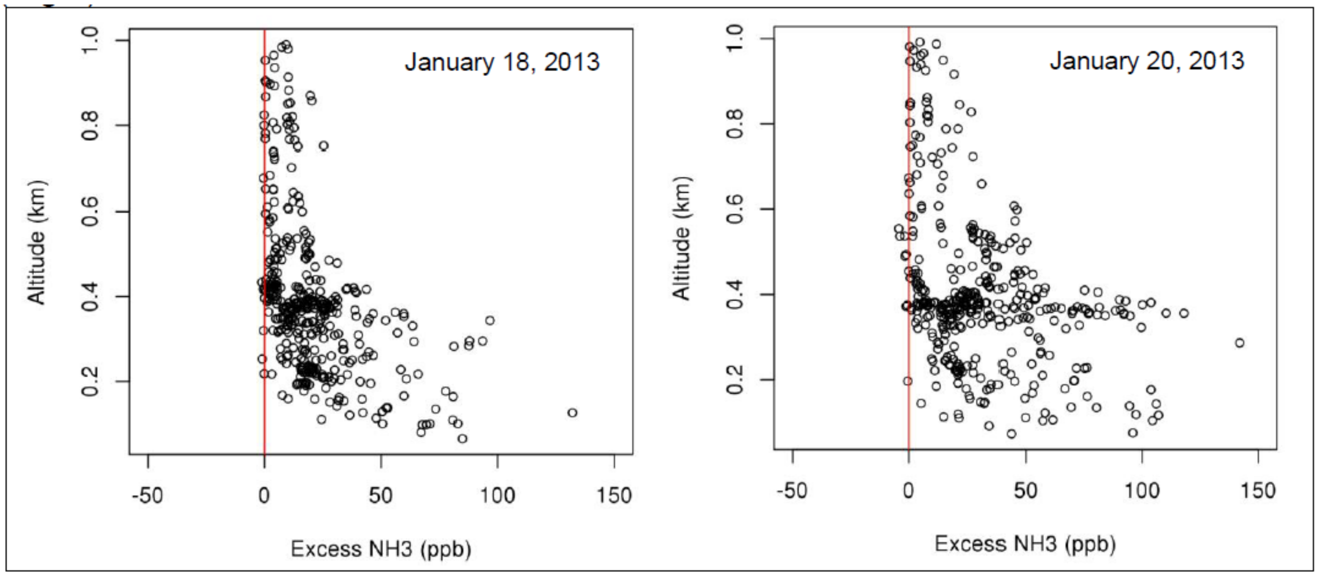
As early as the 1995 Integrated Modeling Study (IMS95), in situ measurements in the San Joaquin Valley indicated the region was ammonia-saturated, which supports NOx being the controlling precursor to ammonium nitrate formation (Kumar et al., 1998; Blanchard et al, 2000). Wintertime measurements five years later during the CRPAQS field study (December 1999 through February 2001) were consistent with the IMS95 findings, where nearly all of the measurements were ammonia-saturated (Lurmann et al., 2006). Lurmann et al. (2006) note that "[t]he consistent excess of NH3 over nitric acid levels indisputably

[33] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 33

shows that secondary ammonium nitrate formation is more limited by nitric acid availability than NH3 within the SJV and in the foothills."[34]

More recent measurements during the DISCOVER-AQ field campaign in January and February 2013 (Parworth et al., 2017; and Figure 2), support previous findings of an ammonia-saturated environment, where a small to moderate reduction in ammonia emissions is likely to have little to no effect on ammonium nitrate concentrations.

**Figure 2. Excess ammonia (NH3) in the San Joaquin Valley on Jan 18 (Left) and Jan 20 (Right) based on NASA aircraft measurements in 2013**




Since ammonium nitrate formation is limited by NOx, reducing NOx emissions is the more effective strategy for reducing ammonium nitrate and PM2.5. Other research has found that ammonia concentrations in the San Joaquin Valley have increased, further confirming that NOx reductions are the most effective path to reducing PM2.5.

A 2017 study using satellite data also aligns with this previous research. Measurements of column-integrated ammonia taken from the Infrared Atmospheric Sounding Interferometer (IASI), an instrument housed aboard the European Space Agency's MetOP-A satellite which passes over California daily, suggest that CARB's emissions inventory currently underestimates ammonia emissions in the Valley. These results suggest the 2018 PM2.5 Plan modeled sensitivity to ammonia reductions is overstated and further reinforces the efforts to develop and deploy ammonia controls would not move the Valley forward on the path to reducing PM2.5 concentrations, and that NOx emissions reductions are the most effective strategy to reduce ammonium nitrate.

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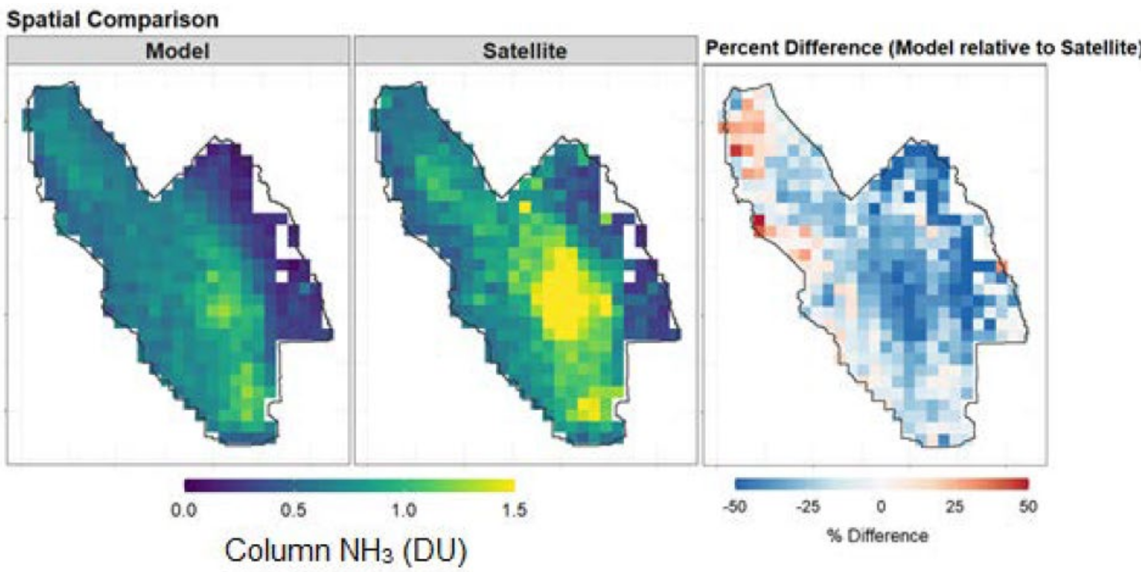
[34] Lurmann et al. "Processes influencing secondary aerosol formation in the San Joaquin Valley during winter." Journal of the Air & Waste Management Association. 2006. Web. 3 Oct. 2017. Page 1688

Figure 3 shows the annual average of column ammonia in 2017 from IASI (Satellite) and Community Multiscale Air Quality (CMAQ) (Model). The model is biased low for column ammonia in the Valley. This bias is most noticeable in Tulare County, where both the model and satellite show an ammonia hotspot, but the model shows about half as much ammonia as the satellite.

**Figure 3. Maps of annual average ammonia from CMAQ (Model; left), IASI (Satellite; middle), and the percentage difference (DU, 1 DU = 2.69e16 molecules/cm2)**




With these new findings from the 2017 study aligning with previous findings from IMS95, CRPAQS, and DISCOVER-AQ, CARB staff's conclusion based on the scientific analysis available continues to be that focusing on NOx emission reductions is key to improving the health of Valley residents and actions to reduce ammonia will not provide significant PM2.5 air quality improvements.

## Future Year Modeling

Analysis of NOx and ammonia emissions trends, discussed above, indicated that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. In accordance with EPA guidance, CARB staff repeated the sensitivity-based analysis of ammonia for the future year of 2024.[35] Staff used an air quality model to estimate the PM2.5 design value for the annual standard in 2024 at each Valley monitor. Then, CARB staff applied a 30 percent

[35] The attainment year for the 15 µg/m3 annual standard, as presented in the 15 µg/m3 SIP Revision, is 2023. Since 2023 is only one year before 2024, precursor sensitivities in 2023 are assumed to be very similar to those modeled in 2024. Thus, CARB's determination in the 2018 PM2.5 Plan—that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the standards in the area—remains the same in relation to the 15 µg/m3 SIP Revision, and CARB continued to exclude ammonia from control requirements in the SIP.

reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values in 2024. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in each attainment year. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in 2024. The results are shown in Table 4.

**Table 4. Future Year 2024 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions**

| Site | 2024 Baseline DV | 2024 DV with 30% Ammonia Reduction | Difference | 2024 DV with 70% Ammonia Reduction | Difference |
|---|---|---|---|---|---|
| **Bakersfield-Planz** | 12.03 | 11.79 | 0.12 | 11.55 | 0.36 |
| **Madera** | 11.98 | 11.77 | 0.21 | 11.32 | 0.66 |
| **Hanford** | 10.52 | 10.26 | 0.26 | 9.77 | 0.75 |
| **Visalia** | 11.09 | 10.97 | 0.12 | 10.71 | 0.38 |
| **Clovis** | 11.37 | 11.27 | 0.10 | 11.05 | 0.32 |
| **Bakersfield-California** | 11.01 | 10.78 | 0.12 | 10.54 | 0.36 |
| **Fresno-Garland** | 10.43 | 10.33 | 0.10 | 10.22 | 0.32 |
| **Turlock** | 11.14 | 10.95 | 0.16 | 10.53 | 0.61 |
| **Fresno-HW** | 10.02 | 9.92 | 0.10 | 9.68 | 0.34 |
| **Stockton** | 10.66 | 10.50 | 0.16 | 10.14 | 0.52 |
| **Merced-S Coffee** | 9.65 | 9.47 | 0.18 | 9.12 | 0.53 |
| **Modesto** | 9.97 | 9.79 | 0.18 | 9.41 | 0.56 |
| **Merced-M** | 8.61 | 8.53 | 0.08 | 8.35 | 0.26 |
| **Manteca** | 7.97 | 7.85 | 0.12 | 7.57 | 0.40 |
| **Tranquility** | 5.54 | 5.42 | 0.12 | 5.19 | 0.35 |

In 2024, the modeled air quality impact of reducing ammonia emissions by 30 percent falls under EPA's adjusted annual threshold of 0.25 µg/m3 for the 15 µg/m3 annual standard at all but one Valley monitor. The estimated air quality impact of reducing ammonia emissions by the upper bound of 70 percent in 2024 exceeds EPA's recommended thresholds for the annual standard at all sites. It is important to note that while EPA recommends a 30 percent analysis, achieving a 30 percent reduction in ammonia is not feasible.

### Relevant Monitors

The impact of ammonia on PM2.5 at monitors that form the basis of the attainment finding for the Valley is the focus of this analysis. For purposes of demonstrating attainment of the PM2.5 standards, the design sites are Bakersfield and Fresno. EPA guidance permits consideration of "the severity of nonattainment at relevant monitors,"[36] and in 2024, PM2.5 levels are not sensitive to ammonia reductions at these design sites.

The Hanford site shows an impact that is 0.01 µg/m3 over the adjusted 0.25 µg/m3 threshold for the 15 µg/m3 annual PM2.5 standard. Based on CARB staff analysis, for Hanford, while the impact is over EPA's recommended significance level, achieving the level of controls needed for a 30 percent reduction of ammonia is not feasible, as discussed below.

### Analysis of Available Emissions Controls

Another factor that may be considered as additional information is available emissions controls on ammonia. The availability of ammonia emissions controls is relevant to the decision-making process, influencing the extent of reasonable modeled reductions. While EPA recommends modeling emissions reductions of between 30 and 70 percent to estimate PM2.5 impacts, CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (i.e., 30 percent), much less at the upper end of the range.

For this supplemental document, at EPA staff's request, CARB and the District have expanded on earlier analyses, assessing potential controls on ammonia sources identified by EPA to analyze the appropriateness of the 30 percent reduction threshold for the precursor analysis.

It is important to note that not all control measure concepts are appropriate to be submitted into the SIP as rules. Any rules that are submitted into the SIP must meet EPA requirements, and should:

- Include enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary to meet the requirements of the Clean Air Act [Act section 110(a)(2)(A)];
- Provide necessary assurances that the State will have adequate personnel, funding, and authority under State law to carry out such SIP (and is not prohibited by any provision of federal or state law from carrying out such SIP) [Act section 110(a)(2)(E)];

[36] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 17

- Be adopted by a State after reasonable notice and public hearing [Act section 110(l)]; and
- Not interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the Act [Act section 110(l)].

The supplemental evaluation of potential controls on ammonia sources identified by EPA is found in Section 3 below.

# 3. Evaluation of Potential Controls on Ammonia Emissions Sources

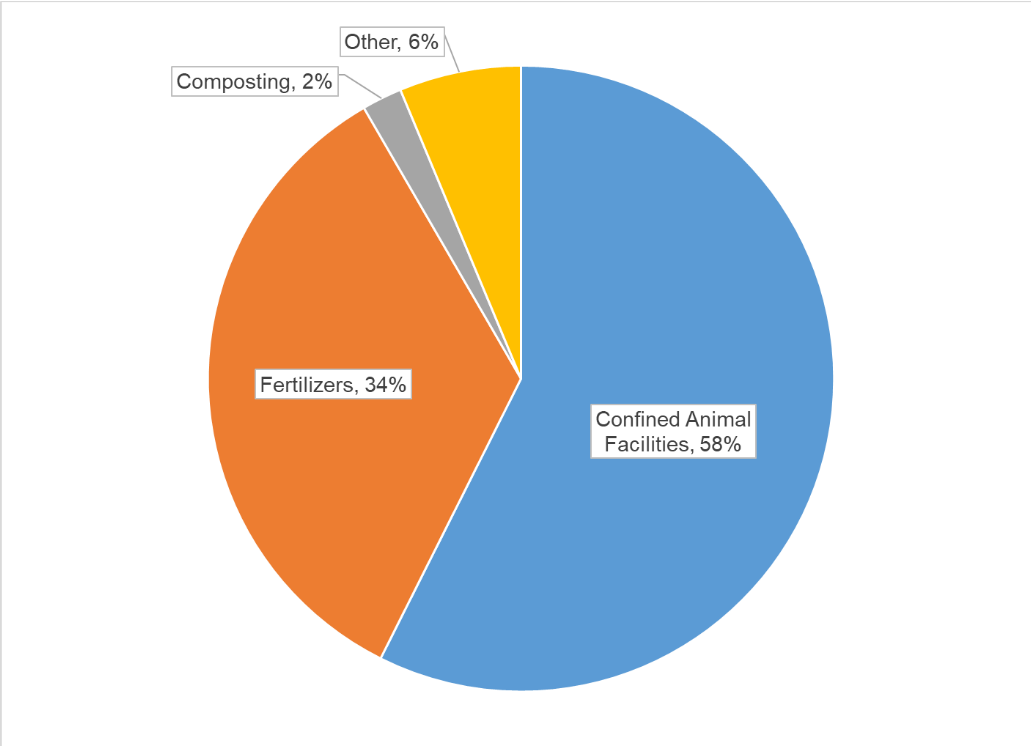
The District and CARB analyzed potential control measures to reduce ammonia emissions in order to evaluate whether a 30 percent reduction in emissions is feasible. For an effective control measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley.

The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions[37], are the focus of the evaluation. Although the base year inventory for the *2018 PM2.5 Plan* is 2013, and previous ammonia technical submittals to EPA have focused on that year, the data and figures below reflect the projected ammonia inventory for 2023. The increased level of control due to the implementation of San Joaquin Valley Air Pollution Control District (District) rules and regulations is already incorporated into the projected emission inventory.

- Confined Animal Facilities (CAFs) with 186.5 tons per day (tpd);
- Agricultural Fertilizers at 111.2 tpd; and
- Composting Solid Waste Operations at 6.7 tpd.

[37] Based on CEPAM 2016 Ozone SIP v1.05 Annual Average Emissions Inventory for 2023

**Figure 4: Sources of Ammonia in the San Joaquin Valley[38]**




Since the primary source of ammonia emissions in the Valley are from CAFs, the District will focus its evaluation on the different types of animal operations, specifically dairies, which account for the majority of ammonia emissions.

The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 5 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from CAFs would need to be further reduced by 52 percent, 87 percent, and 122 percent respectively. As shown in the evaluation below, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions, which may achieve a total of up to 2 percent reduction in emissions notwithstanding technological and economic feasibility considerations. These reductions are not capable of achieving the lower bound level of 30 percent reductions, and the 50 percent and 70 percent reduction levels are infeasible.

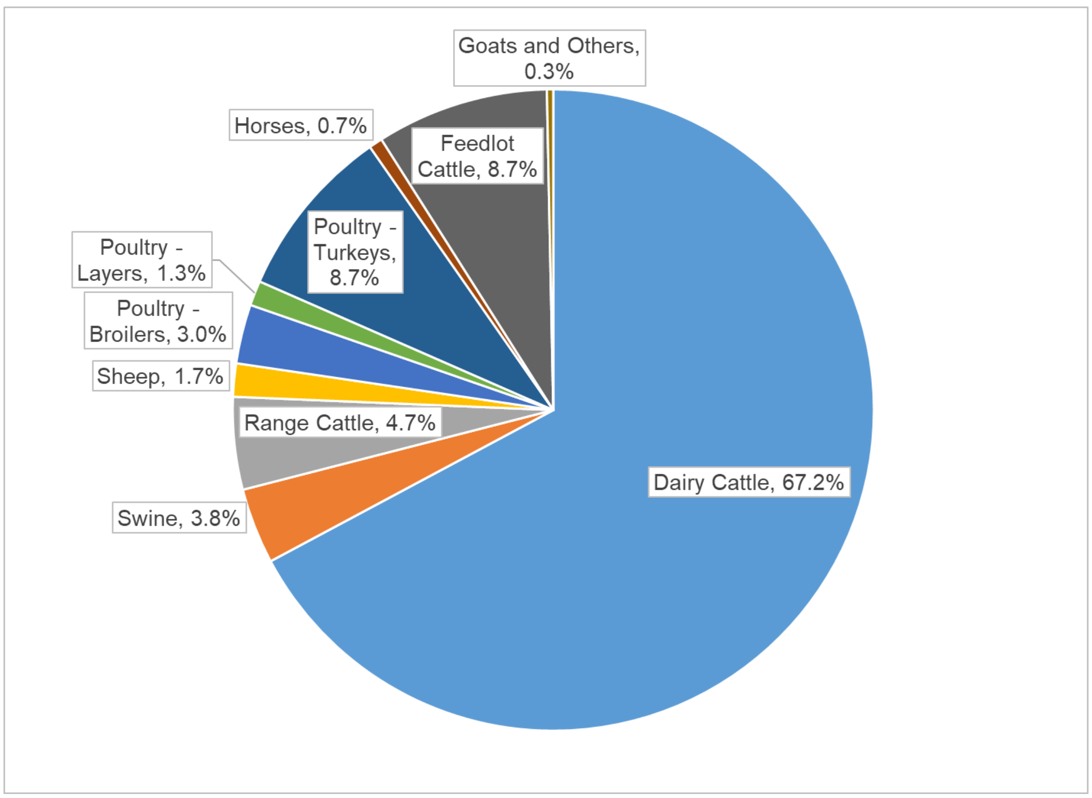
[38] Ibid. 36

**Table 5: CAF Emission Reduction Analysis**

| | 30% Reduction | 50% Reduction | 70% Reduction |
|---|---|---|---|
| Theoretical Ammonia Reductions (tpd) | 97.5 | 162.4 | 227.4 |
| % reduction required from CAFs | 52% | 87% | 122% |

As shown below in Figure 5, dairy cattle emissions account for 67.2 percent of ammonia emissions from CAFs.

**Figure 5: Ammonia from CAFs in the San Joaquin Valley[39]**




The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 6 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from dairy cattle would need to be reduced by 78 percent, 130 percent, and 181 percent, respectively.

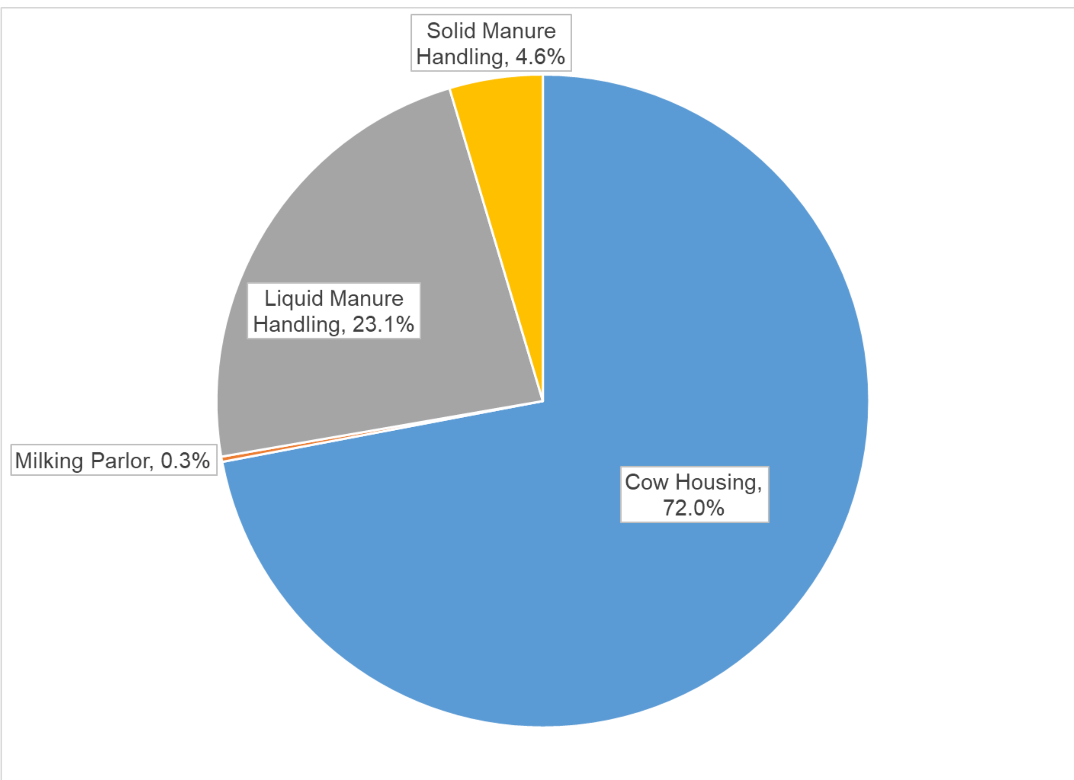
[39] Ibid. 36

**Table 6: Dairy Cattle Emission Reductions Analysis**

| | 30% Reduction | 50% Reduction | 70% Reduction |
|---|---|---|---|
| Theoretical Ammonia Reductions (tpd) | 97.5 | 162.4 | 227.4 |
| % reduction required of dairy cattle | 78% | 130% | 181% |

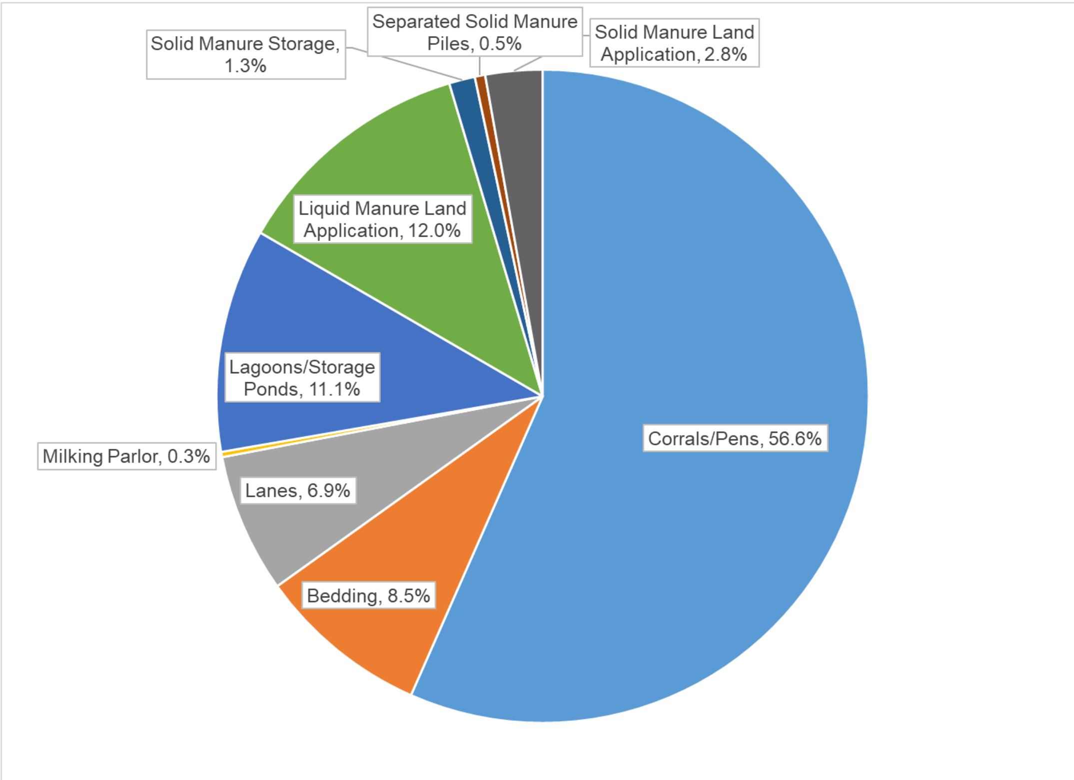
As shown in Figure 6, the primary source of ammonia emissions from dairy cattle is cow housing (72 percent). Figure 7 further evaluates ammonia emissions from dairy cattle by illustrating the different categories such as corrals/pens (56.6 percent), liquid manure land application (12 percent), and lagoons/storage ponds (11.1 percent), etc. Accordingly, the District has provided an evaluation of mitigation measures for dairy cattle focusing on housing, land application techniques, and solid and liquid manure handling.

**Figure 6: Ammonia from Dairy Cattle in the San Joaquin Valley[40]**




[40] Based on District ammonia emission factors for dairy cattle.

**Figure 7: Ammonia from Dairy Cattle in the San Joaquin Valley (cont.)**[41]




Based on the emission inventory analysis above, reducing ammonia emissions by the lower bound precursor demonstration threshold of 30 percent would require eliminating over 50 percent of ammonia emissions from CAFs, or nearly 80 percent of emissions from only dairy cattle, beyond the ammonia emission reductions already achieved by the requirements of District Rule 4570 (Confined Animal Facilities). A 70 percent reduction of ammonia emissions in the District would require the elimination of all CAFs in the District in addition to other categories that have already achieved significant ammonia reductions.

## Inventory of Confined Animal Facilities in the Valley

The District reviewed current permitted facilities in the Valley. Demonstrated below in Table 7 is the count of permitted facilities by type that are subject to Rule 4570, and the controlled ammonia emissions from each type of facility.

[41] Ibid.

**Table 7: Inventory of Confined Animal Facilities in the Valley**

| Facility Type | # of Facilities Subject to Rule 4570[42] | Ammonia Emissions from Facility Type (tpd)[43] |
|---|---|---|
| Dairies | 865 | 125.3 |
| Beef Feedlots | 8 | 16.2 |
| Other Cattle | 77 | 8.7 |
| Chicken – Broilers | 47 | 5.6 |
| Chicken – Layers | 12 | 2.3 |
| Turkeys | 21 | 16.3 |
| Swine | 1 | 7.1 |

## District Rule 4570 (Confined Animal Facilities)

### Background

The largest source of ammonia in the Valley is CAFs. The District has implemented Rule 4570 to reduce emissions from this source category, and requires the most stringent requirements for reducing emissions from CAFs in the nation. Rule 4570 was originally adopted on June 15, 2006, and was again amended on October 21, 2010. District Rule 4570 applies to facilities where animals are corralled, penned, or otherwise caused to remain in restricted areas and primarily fed by a means other than grazing for at least 45 days in any twelve-month period. In addition to limiting volatile organic compound (VOC) emissions, District Rule 4570 includes measures that limit ammonia emissions from these operations.

### Evaluation of District Rule 4570

District Rule 4570 includes multiple mitigation measures that control ammonia emissions from CAFs. Since these facilities generally cover a large area and have different processes, a single mitigation measure or technology is generally not sufficient to control overall emissions from the facility. Due to the varying types of operations and emissions sources at

[42] Review of District permits database (January 2023)
[43] Ibid. 36

these facilities, each CAF requires a site-specific constellation of measures to achieve overall emission reductions.

District Rule 4570 includes a large number of measures that must be implemented by each CAF and also requires additional measures to be selected from a menu of mitigation measures options to achieve additional emission reductions. The menu approach gives the facilities the flexibility to achieve the required emission reductions by selecting mitigation measures that are most practical and effective for their operation. As discussed in the staff report for the 2010 amendments to District Rule 4570,[44] the design and operation of each CAF differs depending on animal type, regional climatic conditions, business practices, and the preferences of the owners/operators. Because of this, no two CAFs are identical. In addition to air quality regulations, CAFs are subject to other regulations to protect water quality and the environment. These additional regulations often restrict how CAFs can operate.

It is not feasible for all CAFs to implement the same measures due to various factors, such as infrastructure, conditional use permits, water quality regulations, production contracts, and other limitations. The options included in District Rule 4570 provide the owners and operators of CAFs much-needed flexibility to choose the mitigation measures that make the best environmental and economic sense for their facility, while maximizing the amount of emission reductions. The required measures have reduced ammonia emissions by over 100 tpd.[45]

## Other Air District Rules

The District provided an in-depth review of Rule 4570 in Appendix C of the *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*), [46] including a comprehensive analysis of Rule 4570, in which the District compared emissions limits, optional control requirements, and work practices in Rule 4570 to comparable requirements in rules from the following areas:

- South Coast Air Quality Management District (SCAQMD) Rule 223 (Emission Reduction Permits for Large Confined Animal Facilities)
- SCAQMD Rule 1127 (Emission Reductions from Livestock Waste)

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[44] SJVAPCD. *Staff Report for 2010 Amendments Rule 4570 (Confined Animal Facilities).* Available at: *http://valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2010/October/Agenda_Item_7_Oct_21_2010.pdf*

[45] Appendix F of the Staff Report for the June 2009 re-adoption of Rule 4570, starting on the 329th page of the pdf available here: *https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2009/June/Agenda%20Item_10_June_18_2009.pdf*

[46] SJVAPCD. *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards.* Appendix C, pages C-311 – C-339. Available at: *https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf*

- Bay Area Air Quality Management District (BAAQMD) Regulation 2, Rule 10 (Large Confined Animal Facilities)
- Ventura County Air Pollution Control District (VCAPCD) Rule 23 (Exemptions from Permit)
- Sacramento Metropolitan Air Quality Management District (SMAQMD) Rule 496 (Large Confined Animal Facilities)
- Imperial County Air Pollution Control District (ICAPCD) Rule 217 (Large Confined Animal Facilities Permits Required) and Policy Number 38 (Recommended Mitigation Measures for Large Confined Animal Facilities)
- Idaho Administrative Procedure Act 58.01.01 Sections 760-764 (Rules for the Control of Ammonia from Dairy Farms)

In addition to these rules, the District's *2016 Plan for the 2008 8-hour Ozone Standard* (*2016 Ozone Plan*)[47] included a comparison of District Rule 4570 to requirements from the following:

- Butte County Air Pollution Control District (BCAQMD) Rule 450 (Large Confined Animal Facilities)
- Yakima Regional Clean Air Agency (Air Quality Management Policy and Best Management Practices for Dairy Operations)

Through the rule comparisons included in the *2018 PM2.5 Plan* and the *2016 Ozone Plan*, the District demonstrated that Rule 4570 was more stringent than the above rules in other areas, at the time of each plan's adoption. The areas mentioned above have not changed or amended their respective rules since the District's previous evaluations, except for the Yakima Regional Clean Air Agency, which rescinded their policy for dairies in 2018. The District has found no new requirements in other areas, but has reevaluated the rules above and found that Rule 4570 continues to implement the most stringent requirements for CAFs.

## Federal Actions and Guidance

The evaluation of appropriate practices and measures to reduce emissions from confined animal facilities requires accurate methodologies to estimate emissions. The National Academy of Sciences identified the lack of methodologies to estimate emissions from animal feeding operations (AFOs) in 2002. In response, EPA announced an opportunity for AFOs to sign a voluntary consent agreement and final order known as the Air Compliance Agreement (2005).[48] The goal of the agreement was to develop scientifically credible methodologies for estimating emission models produced by AFOs. AFOs that chose to participate in the agreement provided the funding for the National Air Emissions Monitoring Study (NAEMS). As part of the agreement, EPA agreed not to sue participating AFOs for certain violations of

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[47] SJVAPCD. *2016 Plan for the 2008 8-hour Ozone Standard*. Available at: *http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/Adopted-Plan.pdf*
[48] See 70 FR 4958. (January 31, 2005). Retrieved from: *https://www.epa.gov/sites/default/files/2016-06/documents/afolagooneemreport2012draftappe.pdf*

the Clean Air Act (CAA), Compensation, and Liability Act (CERCLA), and Emergency Planning and Community Right-to-Know Act (EPCRA), provided that the AFOs comply with the agreement's conditions.

The NAEMS monitored 25 AFOs in various regions of the country to have equipment installed for ammonia, hydrogen sulfide, particulate matter, and VOC emissions monitoring. Separate draft models of swine, poultry, and dairy AFOs emissions were created using the monitoring data and input from the EPA Science Advisory Board.[49]

While data collection took place from 2007 to 2010, these draft models only became publicly available in August 2020, August 2021, and June 2022 for swine, poultry, and dairy AFOs respectively. EPA's final models to estimate emissions from AFOs are not yet available. Currently, EPA projects that finalization of all draft models will occur in late 2023.[50] Though EPA has not provided final guidance on emission estimation methodologies for CAFs, the District has reviewed information from EPA and many other sources in order to use the best information available to calculate emissions from CAFs.

### District Efforts

The District first began permitting agricultural sources in 2004, and since that time District staff members have gained a great deal of experience in the evaluation of emissions from agricultural sources through collaborative efforts with other institutions, agencies, and interested stakeholders. The District has also been thoroughly involved in collaborative scientific research efforts to evaluate emissions from agricultural sources. This is particularly true of the agricultural emissions research efforts in California. The District has played an important role in coordination of these efforts through the San Joaquin Valleywide Air Pollution Study Agency (Study Agency) and the Study Agency's Agricultural Air Quality Research Committee (AgTech). The District has also been at the forefront of developing and implementing regulations to reduce emissions from CAFs.

The District will continue to track the development of rules, regulations, research/studies, and practices for CAFs to ensure the best available control measures and most stringent measures are in place in the Valley, in coordination with industry stakeholders, researchers, CARB, and other agencies.

## Evaluation of Mitigation Measures for Confined Animal Facilities

In the Federal Register posting for the proposed partial approval and partial disapproval of portions of the state implementation plan revisions for the 1997 annual PM2.5 standard,[51]

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[49] Livestock and Poultry Environmental Learning Community. *NAEMS: How It Was Done and Lessons Learned*. April 20, 2022. Retrieved from: *https://lpelc.org/naems/*

[50] EPA. *National Air Emissions Monitoring Study*. Retrieved from: *https://www.epa.gov/afos-air/national-air-emissions-monitoring-study#naems-status*

[51] See 86 FR 38662. (July 22, 2021). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2021-07-22/pdf/2021-15551.pdf*

EPA indicates that further evaluation of potential control measures for ammonia sources is needed. In EPA's proposed disapproval of portions of the *2018 PM2.5 Plan* for the 2012 annual PM2.5 standard,[52] EPA refers to several studies that were cited in a Public Justice comment letter[53] that evaluate CAF mitigation measures that have the potential to achieve additional ammonia reductions. In the same proposal, EPA noted that the United States Department of Agriculture (USDA) National Resources Conservation Service (NRCS) has collaborated to develop a "Reference Guide for Poultry and Livestock Production Systems" (NRCS Reference Guide) [54] that lists 12 measures that may reduce ammonia emissions by more than 30%. EPA also cited a 2011 inventory of mitigation methods by Price et al. prepared for the UK government (UK User Guide) that identifies several ammonia mitigation methods for UK farms.[55]

Following the proposed disapprovals and several meetings with EPA Region 9 staff, the District was provided with a list of mitigation measures generated by EPA Region 9 staff for evaluation, many of which the District has already evaluated over the years. As discussed earlier, it is also important to note that EPA has been committed to addressing emission from livestock operations under a voluntary "safe harbor" consent agreement put into place by EPA in 2005. While the San Joaquin Valley has regulated emissions from livestock operations since 2005, EPA is still in the process of evaluating emissions and establishing the regulatory framework under this consent agreement, and the District will continue supporting the national effort to address emissions from these operations. This list encompassed publications that evaluated potential ammonia emission reductions for either individual mitigation measures or compilations of mitigation measures. The publications provided to the District included a wide variety of mitigation measures such as reducing crude protein content in feed, litter amendments, injection/incorporation of manure, changing land use from arable to woodland, and reducing human consumption of meat and eggs.

Though some of the suggested measures have related studies that appear to demonstrate potential feasibility, it is imperative to consider the conditions under which the studies were performed and how those conditions compare to the Valley. Several of the studies evaluated were conducted in areas outside of California, and many outside of the nation. Notably, CAFs in the Valley face unique challenges, including hot, dry summers, drought conditions,

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[52] See 87 FR 60494. (October 5, 2022). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2022-10-05/pdf/2022-21492.pdf*

[53] Public Justice, et al. (January 28, 2022). Group Comment Letter *Re: Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California*; EPA-R09-OAR-2021-0884. Retrieved from: *https://www.regulations.gov/comment/EPA-R09-OAR-2021-0884-0136*

[54] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[55] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from:
*https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

and strict water regulations, which may not have been considered in some of the publications and studies that evaluated these methods. Valley dairies in particular are typically much larger than dairies in other areas. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California.[56, 57] The UK User Guide, which contains many of the measures evaluated in this document, indicated that the average UK dairy has 170 cows. The differences in climate, typical management practices, size of operations, and regulatory environment affect the types of mitigation measures that can be applied to each operation.

Many of the mitigation measures for consideration by EPA were not applicable to the Valley, were unreasonable or unenforceable, or were based on limited research (e.g. research conducted in other countries with drastically different operating and natural characteristics). The complete list of potential mitigation measures provided by EPA Region 9 staff can be found in Appendix A. The District's evaluation of all potential mitigation measures provided by EPA is included in the following sections.

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[56] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management*. Retrieved from: *https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high*
[57] Latest USDA Statistics for average size of dairies excluding California, retrieved from: *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf* (about 270 cows per dairy outside California)

## Nutrition and Feed Management (Feeding)

**Table 8: Nutrition and Feed Management Measures Evaluated**

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Reducing Crude Protein (Beef) | Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure | Beef | Preece[58] |
| | Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces | Beef | Todd[59] |
| | Reduce Dietary Crude Protein in Beef Cattle | Beef | Cole (2005)[60] |
| Reducing Crude Protein (Dairy) | Reducing Dietary Protein Decreased the Ammonia Emitting Potential of Manure from Commercial Dairy Farms | Dairy | Hristov[61] |
| Reducing Crude Protein (Swine) | Reduce Crude Protein Content from Finishing Pig Houses | Swine | Hayes[62] |

[58] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[59] Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[60] Cole, N., et al., Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure. J. Anim. Sci. 83, 722 (2005).

[61] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

[62] Hayes ET, Leek AB, Curran TP, et al. The influence of diet crude protein level on odour and ammonia emissions from finishing pig houses. Bioresource Technology, 2004

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Feed Timing | Phase, Group, and Split Sex-Feeding | Beef | Cole (2006)[63] |
| | Group and Phase Feeding | All | NRCS[64] |
| | Phase Feeding | All | Guthrie[65] |
| Wet Distillers Grain | Reduce Feeding of Wet Distillers Grain | Beef | Todd[66] |
| Grazing | Increase Grazing Time for Dairy Cattle | Dairy | Guthrie |
| Feed Additives | Feed Additives for Poultry | Poultry | NRCS |

**Reducing Crude Protein Content for Beef Cattle** - ***(applies to beef cattle only)***

EPA noted that studies in 2005 and 2006 found that "*decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.*"

In the 2005 study, steers were randomly assigned to one of nine dietary treatments (three formulated dietary crude protein (CP) concentrations and three supplemental urea:cottonseed meal ratios). Steers were confined to tie stalls, and feces and urine excreted were collected and frozen after approximately 30, 75, and 120 days on feed. As protein concentration in diet increased from 11.5 to 13 percent, in vitro daily ammonia emissions

[63] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006

[64] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[65] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[66] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

increased 60 to 200 percent, due primarily to increased urinary nitrogen excretion. As days on feed increased, in vitro ammonia emissions also increased.

This study had a small sample size with 54 cattle used for nine dietary treatments (six cattle per treatment). These results are only applicable to the finishing cycle of beef cattle lives (four to six months of age), and not applicable to milk cows and support stock at dairies. There are very few finishing cycle feeder beef cattle in the Valley. Most beef cattle in California are beef calves and stockers, fed through grazing. Most of these cattle are sent outside of California for the finishing cycle.[67, 68]

Notably, beef finishing cattle make up a small part of the overall inventory of cattle in the Valley. The current feedlot cattle inventory includes all feedlot cattle; however, the lives of beef cattle are divided into different phases of production. Cow and calf pairs are raised on rangeland. Weaned yearlings/stockers may continue to be raised on rangeland or be sent to yearling/stocker feedlots until a weight of approximately 800 to 900 pounds. Finally, beef cattle are sent to other feedlots out of California for the finishing phase, in which the cattle are fed for four to six months until they reach the desired finished weight. Because of the higher cost of feeding cattle in California and the lack of sufficient beef processing capacity, most of feedlot cattle in California are yearlings/stockers for which this measure does not apply.[69]

If dietary protein concentrations are decreased to the point that animal performance is adversely affected, then total ammonia emissions could be increased because animals require more days on feed to reach market weight and condition. There was also little change in ammonia between the 13 percent and 14.5 percent CP groups.

In the 2006 study, two groups of steers were fed diets with either 11.5 or 13 percent CP and all urine and feces were collected. Manure from steers fed 11.5 percent CP diet had less urine, less urinary nitrogen, and a lesser fraction of total nitrogen in urine, compared with the 13 percent crude protein diet. Decreasing CP in beef cattle diets from 13 to 11.5 percent significantly decreased ammonia emission by 44 percent in closed chamber experiment, and decreased mean daily ammonia flux by 29 percent, 30 percent, and 52 percent in spring, summer, and autumn field trials, respectively. No difference was observed in winter.

Additionally, National Research Council (NRC) Nutrient Requirements of Beef Cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance, prolonging the time necessary to reach market weight and potentially increasing ammonia

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[67] Andersen, M.A., Blank, S.C., LaMendola, T, Sexton, R.J., "California's Cattle and Beef Industry at the Crossroads", California Agriculture 56(5),152-156. Retrieved from: *https://doi.org/10.3733/ca.v056n05p152*

[68] Saitone, T.L., "Livestock and Rangeland in California", Livestock and Rangeland in California. Retrieved from: *https://s.giannini.ucop.edu/uploads/giannini_public/94/c1/94c100fd-9626-47d4-8b82-0bfdb1081a57/livestock_and_rangeland.pdf*

[69] Forero, L., Barry, S., Larson, S. (2021). Beef Cattle on California Annual Grasslands: Production Cycle and Economics. *University of California Agriculture and Natural Resources*. Retrieved from: *https://anrcatalog.ucanr.edu/pdf/8687.pdf*

emissions over the life of the cattle. Because adequate protein levels are required for optimal growth, decreasing CP levels hinder the ability to meet daily weight gain goals.

The overall effectiveness of this measure is unclear because of the small sample size and short period of the study. NRC Nutrient Requirements of Beef cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance. Higher CP levels may be needed to meet daily weight gain goals.

If decreasing the CP content of the diet adversely affects performance, any short-term ammonia reductions can be negated by the longer time on feed required for animals to reach their target market weight and condition.[70] While there may be ammonia reductions in the short term, longer time on feed will result in additional ammonia emissions for the additional amount of time it takes for the animals to reach the appropriate weight. Thus, overall emissions may ultimately be the same, or possibly even increase. Due to the limited pool of data and only studying emissions for 21 days, more research is needed to show a full-cycle of emissions and full impact to the animals.

Despite the uncertainties discussed above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

The feedlot cattle inventory in the Valley includes calves, beef stockers, yearlings, and finishing cattle. This measure is only applicable to beef finishing cattle. It will be conservatively assumed that 50 percent of the feedlot cattle in the Valley are beef finishing cattle. The ammonia emissions from young beef cattle compared to beef finishing cattle will be assumed to be proportional to their nitrogen excretion. Based on information from the American Society of Agricultural and Biological Engineers (ASABE),[71] it is estimated that the average daily nitrogen excretion for beef finishing cattle is 25.7 percent higher than young beef cattle. Therefore, the overall control efficiency for this measure can be estimated as follows:

$$30\% \times 50\% \times 1.257 = 18.9\%$$

No costs for implementation of this measure in the United States could be located. Notably, feed costs are a significant part of the overall costs of raising livestock, often representing as much as 60-70 percent of production costs,[72] and protein is often the most expensive

[70] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006.

[71] American Society of Agricultural and Biological Engineers. (March 2005). ASABE D384.2 Manure Production and Characteristics. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=32018*

[72] Strauch, B.A., Stockton, M.C. (Sep 2013). Feed Cost Cow-Q-Lator. NebGuide. University of Nebraska–Lincoln Extension, Institute of Agriculture and Natural Resources (G2214). Retrieved from: *https://extensionpublications.unl.edu/assets/pdf/g2214.pdf*

component in livestock feed.[73] As a result, beef cattle producers will generally avoid overfeeding protein to minimize productions costs. Therefore, the actual emission reductions from this measure may be significantly lower to nothing since most beef cattle producers will already try to minimize feeding excess protein whenever feasible.

The District has concluded that the measure requires further research on both the effect on production and overall costs, and therefore is not a viable mitigation option to include in Rule 4570 at this time. The District will continue to evaluate the feasibility of this option as practices evolve and further research is conducted.

**Reducing Crude Protein Content for Dairy Cattle** - ***(applies to dairy cattle only)***

In a compilation by Bittman[74] it was recommended that the average CP content of diets for dairy cattle should not exceed 15-16 percent of the dry matter (DM). Phase feeding can be applied in such a way that the CP content of dairy diets is gradually decreased from 16 percent of DM just before calving and in early lactation to below 14 percent in late lactation and the main part of the dry period.

A study[75] measured the effect of reducing the CP content of ammonia emitting potential of dairy manure in a controlled environment. Eleven Pennsylvania dairies with gutter-scrape, gravity-flow, or flush manure-management systems participated in the study. In the study, the CP concentration of the feed for cows that were identified as high-producing cows was decreased from an average of 16.5 to 15.4 percent for the dairies included in the study. Fecal and urine samples were collected from the dairies in the fall of 2009, spring of 2010, fall of 2010, and spring of 2011. The study indicated that laboratory ammonia emissions from reconstituted manure was on average 23 percent lower for the low CP diet versus the high CP diet. No difference was seen in milk yield and milk composition during the low CP and the high CP diet, with average milk yields of 32.2 kg/day and 32.5 kg/day. The researchers that conducted the study concluded that the ammonia emitting potential of dairy manure can be reduced by moderately decreasing dietary CP content.

Although effects of reducing the CP content of the feed for dairy cows may merit further research, there are questions related to the applicability of this study to dairy cattle in the Valley. One important question is if the milk production of the cows in the study is comparable to the milk production of cows in the Valley. The average milk production of the high-producing cows included in the study was only 32.2-32.5 kg/day. In comparison, according to information from USDA National Agricultural Statistics Service, on average, milk

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[73] North Dakota State University (NDSU). (Dec 2019). Comparing Value of Feedstuffs (AS1742). Retrieved from: *https://www.ag.ndsu.edu/publications/livestock/comparing-value-of-feedstuffs*

[74] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds). (2014). "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[75] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

cows in California produced approximately 36.2 kg/day of milk in 2021, [76] with high-producing cows in the Valley producing at a rate of 44 to over 50 kg/day of milk per dairy cow.[77] Therefore, although the cows in the study were identified as high-producing cows that were expected to produce greater amounts of milk, the average milk cow in California produces more milk than the cows in this study. Higher levels of milk production require higher levels of protein, so it is likely that reducing the CP content of feed will reduce milk yields of cows that produce milk.

In communications with the District, Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science, stated that the optimal CP level for high-producing dairy cows in the Valley is around 16.8 percent, which is the level that dairy typically feed their high-producing cows. He also states that when CP levels are decreased to levels that are a little lower than required, milk production tends to be negatively impacted immediately. Dr. Robinson's recommended CP content is based on 14 large on-farm studies that he has completed in the Valley from 2005 to the present. [78] Based on the data he provided from these studies, feed with a CP content of approximately 16.9 percent resulted in maximum milk production for high-producing cows in the Valley, which was about 48.5 kg/day of milk, 50 percent more than the milk production of the high-producing cows in this study. Therefore, 50 percent more high-producing cows would be needed to produce the same amount of milk, which would negate the ammonia reductions from this measure. Another potential issue with the study is that manure samples of a specific size were used to compare the ammonia emitting potential of the manure, but it is unclear if the changes in feed composition affected manure production, which could also affect ammonia emissions.

As discussed above, California dairy operators typically feed their high-producing cows a diet that has CP content near the optimum level of 16.8 percent, and decreasing the CP content of the diet can have an adverse effect on milk production in dairy cattle. Thus, CP reductions for dairy cattle must be closely managed to avoid impacting productivity (e.g., milk yield, fat corrected yield, milk protein yield). Additionally, Dr. Robinson stated that most cows need to recoup body weight during later lactation and that lowering the CP percentage in the diet during this period could have very negative impacts on both milk yield and body weight recovery.

Because nutrient concentrations in feed and feed ingredients vary considerably, reducing CP in diets will require additional lab analyses of feed to ensure that animals receive sufficient nutrients, which will result in increased costs. Dairy operators have no incentive to overfeed

[76] USDA, National Agricultural Statistics Service. Milk Production (February 2022). *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf*

[77] Data from studies of dairy cows in the San Joaquin Valley provided by Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science. *https://animalbiology.ucdavis.edu/people/peter-robinson*

[78] A list of selected scientific publications by Peter Robinson, PhD is available on the UC Davis website at: *https://animalscience.ucdavis.edu/people/faculty/peter-robinson/Articles/Scientific-Publications*

protein since high protein feeds are usually the most expensive ingredients. The percent of CP in the diets fed that California dairy operators feed to dairy cattle has been significantly reduced from previous levels. According to Dr. Robinson, CP in the diets of dairy cows was frequently in excess of 20 percent in the 1980s and 1990s, but that has decreased to the current level of 16.8 percent today. In communication with District staff, Dr. Robert Hagevoort, Extension Dairy Specialist and Topliff Dairy Chair, New Mexico State University, [79] also confirmed similar reductions in the CP content of dairy feed for dairies in the western U.S. compared to previous levels.

In addition, reducing the CP content to the recommended levels is difficult for cattle that graze or are fed a large amount of grass because grass has higher amounts of protein. The NRCS Reference Guide indicates that reduction of CP can also cause deficiency in certain amino acids that can adversely affect animal performance, such as weight gain.

California dairies are expected to continue to try to improve feed efficiency and minimize environmental impacts. However, it is not feasible to require this measure at this time because of questions that remain about the impact on milk production, animal health, and costs on California dairies. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Reducing Protein Content for Swine** - ***(applies to swine only)***

Research indicates that low-protein diets may result in poorer performance in finishing pigs than conventional diets.[80] The NRCS Reference Guide indicates that changes to animal diets generally increase costs because of the time and expense of diet formulation and acquisition of new ingredients, and that the availability of additives and feedstuff fluctuates. Additionally, there are increased costs for low-protein feed due to the need to supplement with amino acids found in protein like crystalline lysine, threonine, tryptophan, methionine and valine. As previously shown, emissions from swine are a small part of the District's ammonia inventory, as there is only one permitted swine facility in the District. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Reduce Feeding of Wet Distillers Grain** - ***(applies to beef cattle only)***

In another study, EPA noted that "one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (ammonia–N/head/day) over nine months, compared with 82 g ammonia–N/head/day at another feedyard feeding lower protein steamflaked, corn-based diets." Nominally, this would represent a 45 percent reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein

[79] *https://dairy.nmsu.edu/faculty-staff/robert-hagevoort.html* (accessed March 15, 2023)
[80] Hayes ET, Leek AB, Curran TP, et al. The Influence of Diet Crude Protein Level on Odour and Ammonia Emissions from Finishing Pig Houses. Bioresource Technology, 2004

intake on the time for beef cattle to reach market weight or on milk production for dairy cows.[81]

This study involved two years of near-continuous ammonia emission data collections at two feedyards. Cattle were fed either conventional feed or wet distillers grains (WDG). Ammonia emissions were 36 percent higher for cattle that were fed WDG.

This study is only applicable to WDG, a feed byproduct of ethanol production. The study notes that WDG typically contains 20 percent or more of protein. That is higher than the ideal diet protein content of 11.5-13.5 percent for beef cattle. This feed is not common in California, because WDG is sold primarily to dairies or cattle feedlots within the immediate vicinity of an ethanol plant, and California only grows 0.07 percent of the nation's corn[82], and produces 0.8 percent[83] of the nation's ethanol. Since dairies in the Valley do not feed WDG, and there is almost no means for WDG feed to be acquired by Valley dairies, this measure is already being implemented and no further emission reductions can be achieved.

**Phase, Group, and Split Sex-Feeding - *(applies to all CAFs)***

The NRCS Reference Guide and a compilation by Guthrie, Giles, etc.[84] focus on mitigation measures for feed management including group and phase feeding, dietary formulation changes, and feed additives. Controlling the protein content of feed is a key element to lowering nitrogen content of manure. Protein naturally contains nitrogen compounds that are often broken down into simple compounds such as ammonia. Group and phase feeding allows the animal to receive the proper nutrition intake by separating animals by age or sex. This allows for a specific diet tailored to each group in order to reduce manure excretion and nitrogen content. Split sex feeding programs are already included as a mitigation option in District Rule 4570 for swine facilities.

The Reference Guide states that dietary formulation changes involve changes in feed ingredients or ration formulations to provide essential available nutrients to meet animal requirements while minimizing excess amounts of nutrients.

Because feed is one of the most significant costs for confined animal facilities, producers work with nutritionists to design diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs. Confined animal facilities work to continually improve feed formulations to deliver nutrients in the amounts required to meet production goals. Overfeeding is undesirable because it will increase costs and farming operations have overall small margins of profit. Operations that overfeed would not be able to compete and would

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[81] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. (2009). "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[82] United States Department of Agriculture - National Agricultural Statistics Service, 2017 Census of Agriculture

[83] U.S. Energy Information Administration, State Energy Data 2020: Production

[84] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

not remain in business because they would not be able to compete with operations that formulate rations for greater efficiency.

As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent.[85] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.[86]

Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production.

As stated above, farms already formulate diets to maximize feed efficiency and minimize excess nutrients. There are many challenges to further dietary changes[87], including:

- Nutrient concentrations in feed and feed ingredients vary considerably; therefore, changing feed formulations of diets will require additional lab analyses of feed resulting in increased costs
- Changes in dietary formulations increase feed costs due to the time and expense of diet formulation and acquisition of new ingredients
- Reduction of crude protein nitrogen can cause deficiency in certain amino acids, such as lysine, threonine, and methionine, that can adversely affect animal performance, including growth and milk production
- Crude protein reductions for dairy cattle must be closely managed to avoid impacting productivity

As discussed above, confined animal facilities already formulate diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs and remain competitive. Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals. Therefore, this measure is already implemented by the confined animal facilities in the Valley and any ammonia reductions from this measure are already being attained.

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[85] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[86] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

[87] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems", pp. 12-13. September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

Phase feeding and split-sex feeding have been commonly used at confined animal facilities throughout the nation for many years, particularly on larger operations,[88, 89, 90, 91] and are a standard practice for the relatively larger confined animal facilities subject to District permitting requirements in the Valley. Because of the higher cost of production in California, confined animal facilities are larger operations compared to other states to take advantage of economies of scale. The standard practice at these operations is to separate animals by phases, ages, or groups that are fed specific diets. At dairies, calves, young heifers, bred heifers, dry cows, milk cows in different stages of lactation, and sick cattle are placed in separate groups and fed rations that are specifically formulated. Beef cattle are separated into cows and calf pairs raised on rangeland, bulls, yearlings/stockers, and finishing cattle, which are fed a separate diet. Broiler chickens are typically fed three to four different diets during their grow-out period and turkeys may be fed up to six diets during their grow-out period to match the specific age or stage of production.[92] It is estimated that genetic selection and the current feed practices have reduced ammonia reduced nitrogen excretion by poultry by up to 55 percent.

Phase feeding is the standard practice in the Valley which also allows for reduction in feed costs and meet production goals. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production. Because phase feeding is in practice at the majority if not all of confined animal facilities in the Valley, any ammonia reductions of this practice are currently being achieved. No additional ammonia reductions are expected from the suggested mitigation measure.

[88] Carter, S., Sutton, A., Stenglein, R. (2012). Diet and Feed Management to Mitigate Airborne Emissions – Air Quality Education In Animal Agriculture. *USDA National Institute of Food and Agriculture*. Retrieved from: *https://lpelc.org/wp-content/uploads/2019/03/Dietand-Feed-FINAL.pdf*

[89] Van Heutgen, E. (2010) Growing-Finishing Swine Nutrient Recommendations and Feeding Management. Pork Information Gateway Factsheets Number PIG 07-01-09. *https://porkgateway.org/resource/growing-finishing-swine-nutrient-recommendations-and-feeding-management/*

[90] USDA Animal and Plant Health Inspection Service (APHIS). Iowa State University (2022) US Poultry Industry Manual - Broilers: brooding. Poultry FAD Preparedness & Response Series. *https://www.thepoultrysite.com/articles/fad-broilers-brooding*

[91] Miles, R.D., Jacob, J.P. (2000) Feeding the Commercial Egg-Type Laying Hen. Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida. *https://ucanr.edu/sites/placernevadasmallfarms/files/102990.pdf*

[92] Moss A, Chrystal P, Cadogan D, Wilkinson S, Crowley T, Choct M. (2021). "Precision feeding and precision nutrition: a paradigm shift in broiler feed formulation?" *Animal Bioscience*, 2021;34(3):354-362. Retrieved from: *https://www.animbiosci.org/journal/view.php?doi=10.5713/ab.21.0034*

**<u>Increase Grazing Time for Dairy Cattle</u> - *(applies to dairy cattle only)***

A compilation by Guthrie[93] states that increased grazing time could reduce ammonia from dairy operations by up to 50 percent as distributed urine can be absorbed into soil and broken down before ammonia is released. However, this practice is not feasible in the Valley, as there is not sufficient land to graze cattle and the arid climate generally requires irrigation to grow crops.

The University of California Agricultural and Natural Resources (UC ANR) publication[94] estimates that the long-term carry capacity of rangeland for grazing in Madera County is 15 or 16 acres per 1,000 lb animal unit; therefore, based on the information in this publication approximately 21-22 acres of unirrigated rangeland would be required to allow a typical 1,400 lb mature dairy cow to graze. The University of California Cooperative Extension (UCCE) publication[95] indicates that 15-18 acres of unirrigated rangeland are required to support a 1,200 lb cow in the Sierra Foothills for one year, and that one acre of irrigated pasture would produce enough forage to feed a 1,200 lb cow for six months. Based on the information in these publications, it is estimated that in the San Joaquin Valley 15-22 acres of unirrigated land would be required for each mature cow to graze for a year, one acre of irrigated pasture would be required for a mature cow to graze for six months, and two acres of irrigated pasture would be required for a mature cow to graze for one year. The enormous amount of land required to graze cattle on non-irrigated land clearly makes this infeasible. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows, not including heifers and calves. Therefore, it is estimated the average dairy in the Valley would require 1,600 acres of land to graze its mature cows for 6 months and 3,200 acres of land to graze its mature cows for one year. Because of the often arid conditions in the Valley, this land would need to be regularly irrigated to sustain sufficient forage for grazing. Additionally, this measure would be impossible to implement as a result of the ongoing severe drought, the Sustainable Groundwater Management Act (SGMA), and limitations on water usage pose severe challenges to the Valley.

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[93] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[94] George, M., Frost, W., and McDougald, N. (December 2020). Ecology and Management of Annual Rangelands Series Part 8: Grazing Management. University of California Agricultural and Natural Resources Publication 8547. https://anrcatalog.ucanr.edu/pdf/8547.pdf

[95] Macon, D., and Meyer, H. (June 2018). How Many Cows Can My Property Support? - Basics of Carrying Capacity, Stocking Rate, and Pasture Irrigation. University of California Cooperative Extension. *UCCE Placer/Nevada Publication 31 1005.* Retrieved from: *https://projects.sare.org/wp-content/uploads/Pub-31-1005-Carrying-Capacity-and-Stocking-Rate.pdf*

The study Survey of Dairy Housing and Manure Management Practices in California[96] reported that in 2007, the average number of milk and dry cows of dairies that responded to the survey in Tulare County was 1,800 cows and that these dairies had 524 acres on which manure was applied to grow feed. Assuming that the acreage for feed production on a dairy in the Valley is proportional to the number of mature cows, the average dairy in Valley with 1,600 mature cows is estimated to have approximately 466 acres of land used for feed production. If half of this land is maintained for feed production and the mature cows at the dairy are grazed on irrigated pasture for six months, the average dairy would require approximately 1,367 additional acres (1,600 acres – 233 acres). For grazing of mature cows on irrigated pasture for the entire year, the average dairy in the Valley with 1,600 mature cows would require approximately 2,734 additional acres (3,200 acres – 467 acres). Information from the USDA National Agricultural Statistics Service indicates that there are currently 965 dairies and 1.5 million milk and dry cows in the Valley. Therefore, 1.5 million acres of irrigated pasture would need to be available for grazing if dairy cows in the Valley graze for just six months and 3 million acres of irrigated pasture would need to be available for dairy cows in the Valley to graze for the entire year.

Because the amount of land needed is not available, this mitigation measure is not feasible in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Feed Additives for Poultry** - ***(applies to poultry only)***

Feed additives such as minerals, antibiotics, and digestive aids are another option to mitigate emissions. These additives can allow for improved nutrient absorption and minimize nitrogen excretion. Feed additives are a mitigation option included in District Rule 4570 for poultry.

Feed additives are more commonly used with poultry than with ruminants, such as cattle, because of the differences in how the digestive system works in ruminants compared to poultry. Additives in the feed of poultry operations can be absorbed by these animals. However, feed and feed additives are pre-digested by rumen bacteria prior to being absorbed in the digestive system of ruminants, which may alter the composition of many feed additives. The use of the rumen bacteria in the digestive system of ruminants that pre-digest feed allows cattle, and other ruminants to utilize various feeds that cannot be digested by non-ruminants.

Rule 4570 requires owners/operators of a layer CAF to implement at least one of the following feed mitigation measures:

- Feed according to NRC guidelines; or
- Feed animals probiotics designed to improve digestion according to manufacturer recommendations; or

[96] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

- Feed animals an amino acid supplemented diet to meet their nutrient requirements; or
- Feed animals feed additives such as amylase, xylanase, and protease, designed to maximize digestive efficiency according to manufacturer recommendations.

Feed is one of the most significant costs for confined animal facilities, therefore producers work with nutritionists to design diets that maximize feed efficiency, increase feed adsorption, and reduce costs. For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.

There are challenges to increase usage of feed additives. Feed is one of the most significant costs of production and feed additives will increase feed costs due to the time and expense of diet formulation and feed additive acquisition. Some additives have negative effects and may increase emissions of some pollutants. The use of antibiotics as feed additives has also been subject to greater restrictions because of efforts to combat increasing bacterial resistance to antibiotics.

The Reference Guide states that many feed additives are already "regularly used to improve nutrient absorption from feed ingredients." Although the Reference Guide suggests that feed additives may improve nutrient absorption and decrease emissions of some pollutants, it does not specify which additives reduce which pollutants for different animals or the amount of each additive required.

Although the suggested measure lacks the specificity needed for a regulation, confined animal facilities already formulate diets to maximize nutrient adsorption, including the use of various feed additives. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals, and the option to utilize various feed additives. Therefore, because this measure is already used by the confined animal facilities in the Valley and included in Rule 4570, any ammonia reductions from this measure are already being achieved in the District.

It is critical for farmers to have the flexibility to decide the kind of mitigation measures that will work best for their specific operation by taking into consideration animal health and welfare, productivity, food safety and overall bio-security issues. The District's menu of feeding options in Rule 4570 provides farmers with this flexibility, while also requiring the most stringent measures for controlling emissions from confined animal facilities.

## Animal Confinement (Housing)

**Table 9: Animal Confinement Measures Evaluated**

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Biofilters and Wet Scrubbers | Enclosed Barns with Biofiltration Systems | Dairy | Kresge[97] |
| | Biofilters | All | NRCS[98] |
| | Install Air-Scrubbers or Biotrickling Filters to Mechanically Ventilated Pig Housing | Swine | Price[99] |
| | Air Scrubbing Techniques | All | Guthrie[100] |
| | Wet Scrubbers | All | NRCS |
| Washing Floors/Lanes | Clean Lanes at Dairies | Dairy | Beene[101] |
| | Washing Floors and Other Soiled Areas in Livestock Facilities | All | Guthrie |
| | Scrape/Flush Freestall Lanes | Dairy | Mendes[102] |

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[97] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. California Institute for Rural Studies.
[98] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[99] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*
[100] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
[101] Beene, M., Krauter, C., Goorahoo, D. (2005). Ammonia Fluxes from Animal Housing at a California Free Stall Dairy. California State University, Fresno. Center for Irrigation Technology and Plant Science Department. Retrieved from: *https://www3.epa.gov/ttnchie1/conference/ei15/session6/beene.pdf*
[102] Mendes, L.B., Pieters, J.G., Snoek, D., Ogink N.W.M., Brusselman, E., Demeyer, P. (2017). Reduction of Ammonia Emissions from Dairy Cattle Cubicle Houses via Improved Management or Design-Based Strategies: A Modeling Approach, In *Science of The Total Environment*, Volume 574, 2017, Pages 520-531, ISSN 0048-9697. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0048969716319970?via%3Dihub*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | Washing Down Dairy Cow Collecting Yards | Dairy | Price |
| Corral Management | Constantly Manage Corrals | Dairy | Card[103] |
| | Frequency of Corral Manure Management | Dairy | Schmidt[104] |
| Floor Design | Floor Design Including Slates, Grooves, V-Shaped Gutters and Sloping Floors to Collect and Contain Slurry Faster | Dairy, Swine | Guthrie |
| | Part-slatted Floor Design for Pig Housing | Swine | Price |
| | Adapt Dairy Housing | Dairy | Pinder[105] |
| | Separate Urine/Manure with 3% Floor Slope | Dairy | Braam[106] |
| Additional Straw Bedding | Additional Targeted Straw-bedding for Cattle Housing | All cattle | Price |
| | Straw Bedding for Cattle Housing | All cattle | Guthrie |
| Other Housing | Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation | All | Guthrie |
| | Oil Spray/Sprinkling | Swine | NRCS |

[103] Card, T. and Schmidt, C. (May 2006). Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Final Report to CARB.
[104] Schmidt, C.E., T. Card, P. Gaffney, and S. Hoyt. (2005). Assessment of Reactive Organic Gases and Amines from a Northern California Dairy Using the EPA Surface Emissions Isolation Flux Chamber. Presented at the 14th Annual Emission Inventory Conference of the U.S. Environmental Protection Agency, Las Vegas, NV.
[105] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*
[106] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences*. Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal | Poultry | Price |
| | More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems | Poultry | Price |
| | In-House Poultry Manure Drying | Poultry | Price |

<u>Biofilters</u> **- *(applies to all CAFs)***

A biofilter is an air filtration and odor mitigation system that channels building exhaust through a mixture of organic materials that support microbial growth. Biofilters have been identified in several publications as a potential ammonia mitigation method, including the NRCS Reference Guide. The reference guide notes many considerations that must be taken into account when implementing these systems, including that they require careful design, monitoring, and maintenance, and have very high associated costs.

Initial costs and challenges include the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop caused by the biofilter. Biofilters require increased retention time; however increasing the retention time usually increases the system static pressure, which can compromise the ventilation system performance. It is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excessive heat from the production house. Lower ventilation airflow may also lead to heat stress in the animals.

Different types of biofilters have their own disadvantages. Flat open biofilter beds are easier to construct and generally cost less; however, they require very large footprints. Vertical biofilters are more difficult to construct and are more expensive, and biological material can settle, causing air leaks, which will reduce the performance of the system. In addition, biofilter media will need to be replaced periodically.

Biofilters require ongoing maintenance to prevent air leakage, dust accumulation, and air constriction in the media to ensure effectiveness of the system performance. Monitoring and maintenance of the filter media moisture is essential to operation of the biofilter, and sprinklers or other wetting systems may be required. Rodents and weeds have also been a problem for some biofilters.

Included in Appendix B, is a cost-effectiveness analysis that demonstrates the economic infeasibility of biofilters. District Rule 4570 does provide options for facilities to use emissions control devices such as biofilters; however, it is not feasible to require all facilities subject to Rule 4570 to install biofilters as they are not cost-effective or practical for livestock facilities in the Valley. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

**<u>Air-Scrubbers/Wet Scrubbers</u> - *(applies to all CAFs)***

Several compilations of mitigation measures, including the NRCS Reference Guide and UK User Guide, list air scrubbing as a potential method of capturing ammonia from animal housing; however, there are considerable costs and challenges associated with the implementation of scrubbers at animal facilities. One such challenge is that off-the-shelf industrial scrubbers are typically not applicable to animal production systems, due to the variation and dynamic changes of such biological systems (e.g., housing structure variation, changes in ventilation airflow rate/pattern in response to the changes of air temperature, manure management practices, unique PM characteristics).

The practicality of scrubbers is limited due to their potential to compromise the ventilation airflow rate needed to control temperature in production houses to ensure animal health. There are added costs for the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop because of the scrubber. Additionally, it is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excess heat from the production house and prevent heat stress in the animals.

Additional costs and challenges to scrubbers include the ongoing maintenance required to prevent dust accumulation and air constriction in the media to ensure effectiveness of the system performance. There are also potential dangers in transporting and handling materials such as acid used in the scrubber. Furthermore, wet scrubbers require large supplies of water and special wastewater handling systems that are not typical at animal production operations. This increased water usage is not practical in the Valley because of limited availability of water due to drought and increasing restrictions on the amount of usable groundwater, due to SGMA.

The UK User Guide identifies installing air-scrubbers as a mitigation method specifically for pig housing, however concludes that the practical application of this method is only to new purpose-built buildings. Included in Appendix B is a cost-effectiveness analysis of scrubbers for swine facilities. The District found that scrubbers are not cost effective, and are therefore not technologically or economically feasible to require in the Valley. District Rule 4570 does provide options for facilities to use emissions control devices such as scrubbers; however, it is not feasible to require all facilities subject to Rule 4570 to install scrubbers. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

**<u>Washing Floors/Lanes</u> - *(applies to all CAFs)***

Several publications include the washing of floors and other soiled areas in livestock facilities as a potential mitigation method to reduce ammonia emissions. The UK User Guide includes a more specific measure involving washing down the concrete areas where dairy cows are collected prior to and after each milking even, through pressure washing or by hosing and brushing.

District Rule 4570 includes the requirement to clean the manure from the lanes, where the majority of manure is excreted, at dairies and other cattle facilities. The majority of cow holding areas at Valley dairies are equipped with sprinkler pens for washing the cows, and are periodically washed throughout the day, rather than scraped once per day.[107] Additionally, Rule 4570 requires constant washing of milking parlor floors to remove manure, which is also standard practice for California dairies. It is essential for all areas of milking parlors, including the milking parlor floors, to be the one of the cleanest parts of the dairy to ensure that the milk from the cows is clean and uncontaminated. There is a constant need for flushing and cleaning of the milking parlor because milk that is contaminated cannot be sold. Therefore, whenever practical, Rule 4570 requires cleaning of areas where the majority of manure accumulates.

Operators of dairy CAFs are required to implement several mitigation measures related to the cleaning of floors/lanes to comply with District Rule 4570, including the following:

Required Measures:

- Flush or hose milking parlor immediately prior to, immediately after, or during each milking;
- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers; and
- Flush, scrap, or vacuum freestall flush lanes immediately prior to, immediately after, or during each milking; or flush or scrape freestall flush lanes at least 3 times per day.

Additional Measures (must select at least one of the following):

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls;
- For a large dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 7 days; or
- For a medium dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 14 days.

Operators of other cattle CAFs are required to implement the following mitigation measures to comply with District Rule 4570:

- Vacuum, scrape, or flush freestalls at least once every 7 days;

[107] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

- Pave feedlanes, where present, for a width of at least 6 feet along the corral side of the feedlane
- Either use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls; or remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade bedding in freestalls at least once every seven days.

In conclusion, the District already requires mitigation measures that require CAFs to wash floors and/or lanes inside of cow housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

**<u>Corral Management</u> - *(applies to all cattle)***

Proper management of manure in animal housing areas will stabilize the nitrogen compounds, which will reduce the rate that these compounds are converted to ammonia that can be lost to the atmosphere. Research by Card and Schmidt (2005) supports that management of manure in corrals reduces ammonia emissions from the corrals and points out that of two dairies tested, the ammonia emissions from the dairy with constantly managed corrals had "exceptionally low ammonia emissions." Follow-up research by Card and Schmidt (2009) at one of the dairies studied indicated that ammonia emissions were significantly reduced (>80 percent reduction comparing 2008 to 2005 reported ammonia emissions) when the frequency of management of the manure in the corrals was increased.

Rule 4570 includes requirements for management of corrals to prevent excessive buildup of manure, designing or managing corrals to prevent excessive moisture, and periodic scraping and removal of manure from corrals. Under Rule 4570, dairy, beef feedlot, and other cattle facilities are required to implement four to six measures for corral management depending on facility type, as well as select one additional mitigation measure as detailed below:

<u>Required Measures</u>

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers (*dairy and other cattle*);
- Clean manure from corrals at least 4 times per year with at least 60 days between cleaning; or clean corrals at least once between April and July and at least once between September and December (*dairy*);
- Scrape corrals twice a year with at least 90 days between cleanings, excluding the removal of in-corral mounds (*beef feedlot and other cattle*);
- Scrape, vacuum or flush concrete lanes in corrals at least once every day for mature cows and every 7 days for support stock; or clean concreted lanes such that the depth of manure does not exceed 12 inches at any point or time (*dairy and other cattle*);
- Inspect water pipes and troughs and repair leaks at least once every 7 days;
- Choose one of the following:
  - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less.  Slope the surface of the corrals at least

1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours; or
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.
- If the CAF has shade structures, they must choose one of the following:
    - Install shade structures such that they are constructed with a light permeable roofing material;
    - Install all shade structures uphill of any slope in the corral;
    - Clean manure from under corral shades at least once every 14 days, when weather permits access into the corral (*dairy*); or
    - Install shade structure so that the structure has a North/South orientation.

<u>Additional Measures</u>

- Manage corrals such that the manure depth in the corral does not exceed 12 inches at any time or point, except for in-corral mounding. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Knockdown fence line manure build-up prior to it exceeding a height of 12 inches at any time or point. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Use lime or a similar absorbent material in the corral according to the manufacturer's recommendation to minimize moisture in the corrals; or apply thymol to the corral soil in accordance with the manufacturer’s recommendation (*dairy and other cattle*).

In conclusion, the District already requires mitigation measures that minimize emissions from corral housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

**<u>Floor Design</u> - *(applies to dairy cattle and swine only)***

Several publications list different floor design types for collecting and containing slurry that may reduce ammonia emissions that include slats, grooves, v-shaped gutters, and sloping floors. The measures included in these documents are applicable to small dairies in which cows are kept in stables or cubicle-type housing that is common on small European dairies in which manure was allowed to accumulate. These measures are also applicable to manure handled as a slurry, and does not apply to the larger dairies in the Valley that are subject to District permitting, which handle very little manure as a slurry.[108] It should also be noted that

[108] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-scale inventory of dairy methane emissions in California: implications for mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

most physical changes to existing dairy barns must be incorporated at the design stage, and are not practical for existing structures, resulting in significantly higher capital costs.

Valley dairies have paved lanes to facilitate manure removal, as required by Rule 4570. The lanes on the dairies are sloped to allow manure to be sent to a lagoon system. In addition, Rule 4570 requires that manure must be periodically removed from the lanes where the cattle spend the majority of their time. Therefore, Rule 4570 already incorporates control measures for specialized floor design and this is already being implemented by dairies in the Valley.

Rule 4570 requirements for dairy and other cattle facilities are as follows:

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers and other cattle.
- For corrals, choose one of the following:
    - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours;
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.

The UK User Guide includes a floor design measure specifically for swine that aims to reduce the overall emitting surface area of slurry by replacing fully slatted floors with part-slatted floors. This type of floor design is already a requirement at the only swine facility in the District. The facility has a specific permit condition that states "Permittee shall use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits." Under Rule 4570, swine CAFs are required to implement measures for animal housing that includes the use of a similar slatted floor system, as follows:

- Use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits.

In conclusion, the District already requires a mitigation measure for swine CAFs to minimize emissions from animal housing areas through the use of a slatted floor system. No additional ammonia reductions are expected from the suggested mitigation measure.

<u>Separate Urine/Manure with 3 Percent Floor Slope</u> - ***(applies to dairy cattle only)***

In one study[109] completed in the Netherlands, ammonia emissions from cubicle housing with a slatted floor, used on small dairies in Europe, were compared with two different solid floor systems: a non-sloped and a 3 percent one-sided sloped floor, combined with a highly frequent or normal removal of manure by a scraper. The study results indicated that the slope of the floor had more impact on reducing ammonia emissions than increasing the scraping frequency. Solid floors with a slope decreased ammonia emissions compared to slatted floors. However, the study indicated that solid floors without a slope may not decrease ammonia emission compared with slatted floors.

Cubicle housing with slatted floors and manure pits under the housing areas are not used for dairy cattle in the Valley. The typical practice is to house cattle in barns or corrals with flushed or scraped lanes. These lanes are sloped to facilitate flushing of the manure to the lagoon system. Additionally, Rule 4570 includes requirements that corrals be sloped, which allows urine to drain away, which reduces the conversion of urea in urine to ammonia since it will have less contact with enzymes in feces that promote this transformation.

District Rule 4570 requires dairy, beef feedlot, and other cattle facilities to implement the following mitigation measure, or an equivalent measure:

- Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal.

In conclusion, the District Rule 4570 already includes mitigation measures involving sloped floors for cattle facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

<u>Additional Targeted Straw-Bedding for Cattle Housing</u> - ***(applies to dairy and other cattle only)***

This method involves adding extra straw bedding to cattle houses, targeting the wetter and dirtier areas of the house. This measure is applicable to small dairy farms that house cattle indoors and use a solid manure handling system, such as small dairy farms in Europe; however, most dairies in the Valley handle the majority of the manure as a liquid and do not use straw bedding. One study[110] indicated that storage or treatment ponds were found on 95.9% of dairies, and another report prepared for CARB states that, "*California dairy effluent*

[109] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences*. Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

[110] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

*often runs 1% total solids."*[111] These dairies also use frequent flushing to remove the manure instead of absorbing with straw, thereby reducing emissions through flushing. Beef cattle in the Valley are not housed indoors; therefore, this measure would not apply to beef cattle in the Valley.

For areas of the dairy that would benefit from this method, the use of straw, or other non-manure based bedding for cow housing is included as a menu option for cattle housed in barns, as shown below:

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls (e.g. rubber mats, almond shells, sand, or waterbeds).

In conclusion, the District already has a mitigation measure option to minimize emissions from cow bedding. No additional ammonia reductions are expected from the suggested mitigation measure.

**Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation - *(applies to all CAFs)***

The compilation by Guthrie, et al.[112] includes ammonia mitigation measures that involve specific building design to provide optimal barn acclimatization. This measure was based on information from the United Nations Economic Commission for Europe (UNECE) compilation Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions.[113] The UNECE publication stated that for cattle cubicle housing was considered the reference and that for cattle housed in cubicles with traditional slats, and claimed that this measure can moderately reduce ammonia by 20% compared to conventional cubicle housing.

Cubicle housing with traditional slats is not typically used to house cattle in the Valley; therefore, this measure is not applicable to cattle in the Valley. In cubicle housing with traditional slats, the manure that cattle excrete seeps through the slats and falls to an alley or a storage pit below the housing area. In the Valley, dairy cattle are typically housed in barns or corrals with lanes that are flushed or scraped to remove manure to a separate area for storage. In cubicle housing with traditional slats, a large amount of the ammonia emissions are from the manure stored in an alley or pit below the housing area. Therefore, this measure

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[111] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

[112] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[113] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

would not reduce ammonia emissions from cattle housing in the Valley because manure is stored in a different area.

In addition, these measures are not feasible for many existing buildings and must be incorporated in the initial design stage of a new build. For poultry, new houses generally incorporate insulation and controlled ventilation. However, this measure is generally not feasible for implementation at Valley dairies or other cattle facilities. Due to the warm climate in the Valley, barns used for cattle consist of a roof with open sides to allow for adequate airflow and cooling. These structures would need to be completely redesigned and reconstructed to implement this mitigation measure, and there would be substantial cost to enclose the cattle and equip the barns with ventilation systems to supply sufficient airflow for the cattle. Furthermore, the increased airflow from the fans required for ventilation may promote increased emissions from the barns rather than reduce ammonia.

In conclusion, the suggested measure is not applicable to cattle facilities in the Valley and would not result in any additional ammonia reductions.

**Oil Spray/Sprinkling - *(applies to swine only)***

Sprinkling of vegetable oil in animal production areas has been demonstrated as an effective measure within swine barns for PM mitigation, with observed smaller reductions of ammonia ranging from 0-30 percent. However, results of research on the effect of this practice on ammonia emissions vary greatly.[114] This practice requires daily labor if applied by hand, and requires additional time during room washing to remove oil residue. Additionally, oil residue can cause ventilation fans to become stuck in on or off positions, preventing them from operating correctly to ensure proper ventilation and cooling of animals. As mentioned above, current research shows considerable variability in the potential ammonia emission reductions of this measure; therefore, it is currently uncertain if this measure will reduce ammonia emissions and the magnitude of any potential reductions. Furthermore, the NRCS Reference Guide indicates that this measure is applicable to swine barns, which contribute a very small amount to the District's ammonia inventory with only one permitted facility in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal - *(applies to poultry only)***

This measure applies to high-rise laying hen housing with deep pit storage. In a deep-pit storage system, laying hens are kept in tiered cages and the manure from laying hens drops into a pit below the cages where it may be stored for months prior to removal. The UK User Guide identifies that replacing this system with a series of belts below each tier of cages,

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[114] Harmon, J., Hoff, S., Rieck-Hinz, A. (2014). Animal Housing – Vegetable Oil Sprinkling Overview. *Air Management Practices Assessment Tool*, Iowa State University. Retrieved from: *https://store.extension.iastate.edu/product/Animal-Housing-Vegetable-Oil-Sprinkling-Overview*

which remove manure from the house, could have the potential to reduce ammonia emissions.

In the United States, the overall trend for farms that produce eggs has been to shift away from high-rise laying hen housing with tiered cages to cage-free housing. In 2018, voters in California approved Proposition 12, also known as the Farm Animal Confinement Initiative.[115] Proposition 12 requires that animals held in buildings, such as laying hens, breeding sows, or veal calves, *"be housed in confinement systems that comply with specific standards for freedom of movement, cage-free design, and minimum floor space."* Implementation of the law began on January 1, 2022, and as a result all eggs produced in California must be procured only from hens in cage-free housing. High-rise hen houses in which egg-laying hens are kept in cages are no longer legal in California. There are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

**More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems - *(applies to poultry only)***

This method identified in the UK User Guide increases the frequency of manure removal to twice weekly, and relies on the rapid removal of manure from the house prior to the peak rate of ammonia emission. This measure is only applicable to laying hen houses that are already equipped with belt manure removal systems, and is not feasible for the majority of existing laying hen houses in the Valley given the significant facility reconstruction costs and potential space/infrastructure limitations at existing facilities.

In addition, as explained above, all eggs produced in California must be procured only from hens in cage-free housing and there are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

**In-House Poultry Manure Drying - *(applies to poultry only)***

In-house poultry manure drying, as identified in the UK User Guide, is applicable to poultry housing, and involves the installation of ventilation/drying systems that reduce the moisture content of poultry litter. The author expects implementation of this method to be low to moderate, due to the practical limitations involved with installing systems in existing buildings. Forced air drying systems are not feasible for houses in which the birds are raised on litter because the litter remains in the houses with the birds until cleaned out to prepare

[115] California Proposition 12, Animal Care Program. Retrieved from: *https://www.cdfa.ca.gov/AHFSS/AnimalCare/*

for another flock. Following BACT Guidelines 5.7.1[116] and 5.7.2[117], this practice is evaluated as a potential BACT measure for new or expanding facilities; the required mitigation measure is as follows:

- Completely enclosed mechanically ventilated layer housing with evaporative cooling pads, mixing fans, and a computer control system.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new poultry housing operations. No additional ammonia reductions are expected from the suggested mitigation measure.

## Manure Management (Storage)

**Table 10: Manure Management (Storage) Measures Evaluated**

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Lagoon Management | Replace Lagoons with Deep Tanks | Dairy | Guthrie[118] |
| | Oxygenation of Liquid Manure Lagoons | All | NRCS[119] |
| Storage Bags | Storage Bags | Dairy | Guthrie |
| Manure Storage Covers | Liquid Manure Storage Covers | All | NRCS |
| | | All | Marks[120] |
| | Solid Manure Storage Covers | All | NRCS |

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116 https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID773.pdf?:linktarget=_self&:embed=yes
117 https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID774.pdf?:linktarget=_self&:embed=yes
118 Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
119 EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
120 Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | | All | Price[121] |
| | | All | Chadwick[122] |
| | Allow Cattle Slurry Stores to Develop a Natural Crust | Dairy | Price |
| Solid-Liquid Separation | Solid-Liquid Separation | All | NRCS |
| Anaerobic Digesters | Anaerobic Digesters | Dairy | NRCS |
| | | Dairy | Marks |
| | | Dairy | Kresge[123] |
| Amendments/Additives | Litter Amendments and Manure Additives | All | NRCS |
| | Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium | All | Guthrie |
| | Acidifying Amendments and Additives for Poultry Litter | Poultry | Price |

[121] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[122] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X*

[123] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. *California Institute for Rural Studies.*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | Urease Inhibitors | All Cattle | Pinder[124] |
| | | All Cattle | Preece[125] |
| Surface Cooling | Surface Cooling of Slurry Manure | All | Guthrie |
| pH of Manure | Lowering pH of Manure | All | Preece |
| On-farm Composting | Composting | All Cattle | NRCS |

**Replace Lagoons with Deep Tanks** - ***(applies to dairy cattle only)***

A compilation[126] indicated that replacing lagoons with deep tanks can reduce ammonia emissions by 30-60 percent. The information from the compilation indicates that this measure is applicable to manure that is handled as a slurry. The reductions in ammonia emissions are a result of the smaller surface area of the manure in contact with the air from which ammonia may be emitted. Storage of manure in deep tanks is not a feasible measure for the District due to the size of dairies in the Valley and the way that manure is typically handled. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California[127, 128] and are larger than the typical European dairies for which this measure was considered. In addition, dairies in the Valley typically handle liquid manure as a dilute liquid with rather than a thick slurry.

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[124] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[125] Preece, S., Cole, N., Todd, R., Auvermann, B. (2017). Ammonia Emissions from Cattle Feeding Operations. *Texas A&M AgriLife Extension Service.* Retrieved from: *http://baen.tamu.edu/wp-content/uploads/sites/24/2017/01/E-632.-Ammonia-Emissions-from-Cattle-Feeding-Operations.pdf*

[126] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[127] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management.* Retrieved from: *https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high*

[128] Latest USDA Statistics for average size of dairies excluding California. Retrieved from: *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf* (about 270 cows per dairy outside California)

The dilute dairy manure typically handled in the Valley has a solids content of 2 percent or less while slurry manure has a solids content of about 10 percent. As a result, the volume of manure handled would be approximately 27 times greater than the average dairy outside of California that handles dairy manure as a slurry. It is not practical to construct tanks that would contain such large amounts of manure. Notably, the depth of lagoons and storage ponds is limited to protect groundwater because a minimum distance is required between the bottom of the lagoons and storage ponds and the groundwater.[129,130] Therefore, the tanks would need to be constructed aboveground. However, it is not practical to construct tanks aboveground because of the large amount of liquid manure that must be stored. Pumping the manure into aboveground tanks would require larger amounts of energy. Also, it is possible the release of the ammonia conserved in the manure tanks will be delayed until the manure is sent to a storage pond or applied to land. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Oxygenation of Liquid Manure Lagoons** - ***(applies to all CAFs)***

The NRCS Reference guide states that large land footprint of naturally aerobic lagoons is not practical for many farms. This is particularly applicable to the large farms in the Valley. Naturally aerobic lagoons are not feasible in the Valley because the dairies in the Valley would require an extremely large footprint. The design criteria of naturally aerobic lagoons in the USDA-NRCS Practice Standard Code 359 will be used to illustrate the approximate size that would be required for naturally aerated lagoons for confined animal facilities in the Valley. USDA-NRCS Practice Standard Code 359 requires that naturally aerobic lagoons be designed to have a minimum treatment surface area as determined on the basis of daily $BOD_5$ loading per unit of lagoon surface. The standard specifies that the maximum loading rate of naturally aerobic lagoons shall not exceed the loading rate indicated by the USDA-NRCS Agricultural Waste Management Field Handbook (AWMFH)[131] or the maximum loading rate according to state regulatory requirements, whichever is more stringent.

According to Figure 10-30 (August 2009) of the latest version of the AWMFH, the maximum aerobic lagoon lading rate for the Valley is 45 - 55 lb-$BOD_5$/acre-day. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows. Based on a typical dairy herd composition, the average dairy in the Valley is estimated to have approximately 1,348 milk cows, 252 dry cows,

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129 California Regional Water Quality Control Board Central Valley Region Order R5-2013-0122 – Reissued Waste Discharge Requirements General Order for Existing Milk Cow Dairies. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

130 California Regional Water Quality Control Board Central Valley Region Order R5-2017-0058 –Waste Discharge Requirements General Order for Confined Bovine feeding Operations. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2017-0058.pdf*

131 United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS), Agricultural Waste Management Field Handbook (AWMFH). Retrieved from: *https://directives.sc.egov.usda.gov/viewerfs.aspx?hid=21430*

and 1,153 heifers and calves. According to Table 4-5 (March 2008) of the USDA-NRCS AWMFH, the total daily manure produced by each milk cow, dry cows, and 970 lb heifer will have an average BOD loading of 2.9 lb-$BOD_5$/day, 1.4 lb-$BOD_5$/day, and 1.2 lb-$BOD_5$/day, respectively. The average BOD loading of manure produced by smaller heifers and calves is estimated based on manure volatile solids excretion rates. Assuming that 80 percent of the manure will be flushed to the lagoon system, the minimum lagoon surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley with 1,600 milk and dry cows can be calculated as follows:

<u>$BOD_5$ loading (lb/day)</u>

1,348 milk cows x 2.9 lb-$BOD_5$/cow-day x 0.80 = 3,127 lb-$BOD_5$/day

252 dry cows x 1.4 lb-$BOD_5$/cow-day x 0.80 = 282 lb-$BOD_5$/day

457 heifers (15-24 months) x 1.2 lb-$BOD_5$/heifer-day x 0.80 = 439 lb-BOD5/day

366 heifers (7-14 months) x 0.83 lb-$BOD_5$/heifer-day x 0.80 = 243 lb-$BOD_5$/day

182 heifers (4-6 months) x 0.47 lb-$BOD_5$/heifer-day x 0.80 = 68 lb-$BOD_5$/day

148 calves (0-3 months) x 0.27 lb-$BOD_5$/heifer-day x 0.80 = 32 lb-$BOD_5$/day

Total BOD loading = 3,127 lb-$BOD_5$/day + 282 lb-$BOD_5$/day + 439 lb-$BOD_5$/day + 243 lb-$BOD_5$/day + = 68 lb-$BOD_5$/day + 32 lb-$BOD_5$/day = 4,191 lb-$BOD_5$/day

<u>Minimum Surface Area Required for a Naturally Aerobic Lagoon for an Average San Joaquin Valley Dairy</u>

Minimum Surface (acres) in areas with a maximum loading rate of 55 lb-$BOD_5$/acre-day =

4,191 lb-$BOD_5$/day ÷ 55 lb-$BOD_5$/acre-day = 76.2 acres

Minimum Surface (acres) in areas with a maximum loading rate of 45 lb-$BOD_5$/acre-day =

4,191 lb-$BOD_5$/day ÷ 45 lb-$BOD_5$/acre-day = 93.1 acres

As shown above the minimum surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley would range from approximately 76.2 – 93.1 acres. This amount of land is not typically available and would require the removal of land that is currently used to produce feed or other crops. Construction of a lagoon over 76 acres in size would be a massive project that would have numerous challenges and high costs for both design and construction. For example, the expense of lining a lagoon of this size would be extremely high. To comply with the requirements of the Central Valley Regional Water Quality Control Board, new lagoons and ponds that store dairy manure in the Valley have generally needed to comply with the Central Valley Regional Water Quality Control Board Tier 1 design standards, which require a lagoon or pond with a double liner constructed of high density polyethylene (HDPE) or material of equivalent durability with a leachate collection and removal system. The Capital Press article[132] indicated that the cost for the installation of double-liner for an existing lagoon at a dairy near Sunnyside, Washington in 2016 was roughly $500,000 for each lagoon and the lagoons averaged 78,000 square feet each. Based on this information, the cost of a double liner for a lagoon storing dairy manure is estimated to be about $7.88 per square foot and $343,253 per acre in 2022. Therefore, the cost for the liner for a lagoon only with an area of 76.2 to 93.1 acres would be $26,555,879 to $31,956,854.

In addition to construction costs, there would also be an increase in expenses for designing and maintaining lagoons of such a large size. To comply with the requirements of Regional Water Quality Control Board and Mosquito Abatement District the lagoon would need to be regularly cleared of any dead algae, vegetation, and floating debris that could create a habitat for mosquitos and other vectors that carry diseases. Therefore, as a result of the large size of the lagoons, the maintenance required to comply with these regulations would be difficult and there would also be increased costs. Finally, ammonia emissions may increase from naturally aerobic lagoons because of the large surface in contact with the atmosphere.

The NRCS Reference Guide states that the energy required at an animal production operation to introduce enough oxygen for complete aerobic treatment using mechanical aeration is very expensive and aeration of the surface of the liquid manure is more common.

The Government of Ontario publication[133] states that there are several disadvantages for on-farm use of mechanical aeration and specifically lists the following:

- High initial costs
- High energy costs
- High maintenance costs
- Effectiveness is reduced in cold weather
- The introduction of antibiotics and sanitizers can upset or destroy the required aerobic bacteria
- Nitrogen loss to the atmosphere is increased with mechanical aeration

This publication cautions that improperly designed mechanical aeration systems may contribute more odor than what is reduced through the mixing of air into the liquid, which indicates that mechanical aeration of manure can increase emissions.

The very high cost of complete mechanical aeration makes this option infeasible for farms. For complete aerobic treatment of a lagoon, sufficient oxygen must be delivered into the lagoon and the oxygen delivered must be completely mixed throughout the lagoon. A report

[132] Wheat, D. (2018). Dairy Installs Double Liner in Its Lagoon. Capital Press. Updated December 13, 2018. Retrieved from: *https://www.capitalpress.com/state/washington/dairy-installs-double-liner-in-its-lagoon/article_9ded077e-db11-5cc5-adb7-aa7ebee6e5b9.html*

[133] Government of Ontario. (2006). "Aeration of Liquid Manure". Retrieved from: *https://www.ontario.ca/page/aeration-liquid-manurehttps://www.ontario.ca/page/aeration-liquid-manure*

by the University of California (UC) Davis[134] states, "*Mixing is important to ensure uniformity of temperature and composition throughout the volume, e.g., continuous bulk turnover is needed to eliminate quiescent zones or sludge layers where anaerobic conditions persist. Also, relatively vigorous mixing (high turbulence) prevents clumping of organisms/substrate, and reduces diffusion resistance by thinning the film thickness through which dissolved oxygen must migrate (diffuse) to reach substrate particles and organisms.*" Delivery of oxygen and mixing of the oxygen throughout a lagoon requires substantial amounts of energy. The cost of electricity for complete aeration can be estimated based on the amount of oxygen that needs to be supplied and the energy required for complete mixing of oxygen throughout a lagoon. The Government of Ontario publication indicates that for complete aeration of manure, oxygen must be supplied in an amount equal to twice the BOD in the manure.

A publication[135] indicates that approximately 1.5 to 2.5 pounds of oxygen is required to digest one pound of Biological Oxygen Demand ($BOD_5$) with additional oxygen required for conversion of ammonia to nitrate (NO3-) (nitrification). In this publication, Dr. Ruihong Zhang of UC Davis estimated that 2.4 lbs (1.1 kg) of oxygen ($O_2$) per cow must be provided each day for removal of BOD and an additional 3 lbs (1.4 kg) per cow for oxidation of 70 percent of the nitrogen, which is a ratio of approximately 2.25 lb of oxygen per lb of BOD. It will be estimated that 2 lb of oxygen per 1 lb of $BOD_5$ is required for nitrification of ammonia.

As discussed above, the lagoons for an average size dairy in the Valley with 1,600 mature cows will have a BOD loading rate of approximately 4,191 lb-$BOD_5$/day. Based on the data gathered in the UC Davis report, aeration efficiencies for mechanical aerators ranged from 0.10 to 0.68 kg of oxygen provided per kW-hr of energy utilized.[136] The most efficient aerator tested installed in dairy lagoons had an aeration efficiency of 0.49 kg-$O_2$/kW-hr. These efficiency tests were performed in clean water. The efficiency of the aerators will be lower in liquid manure because of the higher amount of solids that it contains compared to clean water. The yearly energy requirement for a mechanically aerated lagoon treating flushed manure an average size dairy in the Valley is calculated as follows:

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[134] Williams, R.B., Elmashad, H., Kaffka, S. (2020). Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology. *University of California, Davis, California Biomass Collaborative*, CARB Agreement No. 17TTD010. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/ucd_ammp_qm_analysis_final_april2020.pdf*

[135] San Joaquin Valley Dairy Manure Technology Feasibility Assessment Panel. (2005) An Assessment of Technologies for Management and Treatment of Dairy Manure in California's San Joaquin Valley. California Air Resources Board

[136] Zhang, R., Sun, H., Kamthunzi, W.M., Collar, C.A., Mitloehner, F.M. (2007) Aerator Performance for Wastewater Lagoon Application, ASABE. *https://elibrary.asabe.org/abstract.asp?aid=23832*

Oxygen Requirement for Average Size Dairy in the Valley

4,191 lb-$BOD_5$/day x 1 kg/2.2046 lb = 1,901 kg-$BOD_5$/day x 2 = 3,802 kg-$BOD_5$/day

Electricity for High Efficiency Aerator

3,802 kg-$BOD_5$/day ÷ (0.68 kg-$O_2$/kW-hr) x (365 day/year) = 2,040,779 kW-hr/year

Electricity for Low Efficiency Aerator

3,802 kg-$BOD_5$/day ÷ (0.10 kg-$O_2$/kW-hr) x (365 day/year) = 13,877,300 kW-hr/year

Electricity for Complete Mixing of Air

The UC Davis report estimates that mixing for complete aeration of a dairy lagoon would require 3,300 kW-hr per milk cow per year. The energy required for mixing for complete aeration for an average sized dairy in the Valley is calculated as follows:

1,348 milk cows x 3,300 kW-hr/milk cow-year = 4,448,400 kW-hr/year

Total Electricity Required for Complete Aeration with High Efficiency Aerator

2,040,779 kW-hr/year + 4,448,400 kW-hr/year = 6,489,179 kW-hr/yr

Total Electricity Required for Complete Aeration with Low Efficiency Aerator

13,877,300 kW-hr/year + 4,448,400 kW-hr/year = 18,325,700 kW-hr/yr

Cost of Electricity for Complete Mechanical Aeration of a Lagoon Treating Manure from an Average Size Dairy in the Valley:

The cost for electricity will be based upon the average price for industrial electricity in California for the year December 2021 through November 2020, as taken from the Energy Information Administration (EIA) website:

Average Cost for electricity = $0.1685/kW-hr

The electricity costs for complete aeration are calculated as follows:

Low Cost Estimate (High Efficiency Aerator)

6,489,179 kW-hr/year x $0.1685/kW-hr = $1,093,427/year

High Cost Estimate (Low Efficiency Aerator)

18,325,700 kW-hr/year x $0.1685/kW-hr = $3,087,880/year

As shown above, the estimated cost for only the electricity for a mechanically aeration to reduce ammonia emissions from an average size dairy in the Valley ranges from nearly $1.1 million per year to nearly $3.1 million per year. This cost does not include the design and construction of the mechanical aeration system or any additional operational costs. However, it is clear that the cost of electricity alone would make this system economically infeasible, especially when considering that the price of electricity is expected to continue to increase.

Although the NRCS Reference Guide states that surface aeration of manure is more common because of the difficulty and expense of complete mechanical aeration, the amount of oxygen provided by aeration of the surface of liquid manure would not be sufficient to oxidize ammonia. Any ammonia oxidized would be converted to nitrite and nitrate. Increased concentrations of nitrite and nitrate in the liquid manure may require treatment to protect water quality or increase emissions of NOx or nitrous oxide (N2O).

Although surface aeration may sometimes reduce odors of some compounds, surface aeration may actually increase ammonia emissions because it accelerates the release of carbon dioxide (CO2), an acidic gas, which increases the pH of the manure promoting increased ammonia emissions.[137, 138] Additionally, low levels of aeration will not provide sufficient oxygen for treatment, but can increase the transfer of emissions from the manure to the air because of the increased disturbance at the surface of the liquid manure.

Naturally aerated lagoons are not feasible in the Valley because of the large land requirements, fully mechanically aerated lagoons are not practical because of the high energy requirements and costs, and surface aeration is not expected to reduce ammonia emissions; therefore, this is not a feasible measure to reduce ammonia emissions from liquid manure in the Valley.

The District is unaware of any instances in which oxygenation demonstrates to be a practical technology on any farm to decrease ammonia emissions from liquid manure and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**<u>Storage Bags</u> - *(applies to dairy cattle only)***

Manure storage bags have primarily been used to store manure from pig farms in Europe and Canada. They have also recently started to be used to store manure on some dairy farms that are relatively small compared to the typical dairies in the Valley. The storage of manure in bags is only suitable for small dairies that handle manure as a slurry. Manure storage bags are not suitable for large dairies that handle dilute liquid manure because of the large volumes of manure that must be stored until it can be applied to cropland. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. Dairies that handle

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[137] Zhao, B., Chen, S. (2003). Ammonia Volatilization from Dairy Manure under Anaerobic and Aerated Conditions at Different Temperature. Paper number 034148, 2003 American Society of Agricultural and Biological Engineers Annual Meeting. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=13892*

[138] Kaffka, S., Barzee, T., El-Mashad, H., Williams, R., Zicari, S., Zhang, R. (2016). Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California. Final Technical Report to the State of California Air Resources Board Contract #14-456. Retrieved from: *https://biomass.ucdavis.edu/wp-content/uploads/ARB-Report-Final-Draft-Transmittal-Feb-26-2016.pdf*

manure as a slurry without the addition of water are extremely rare in the Valley. [139] In addition, lagoons and storage ponds that hold manure are required to be lined in order to reduce the chances of manure contaminating the groundwater. Manure storage bags may not be allowed because there is a high possibility that something may puncture the bag causing manure to leak, which could degrade groundwater.

The District is unaware of any dairies in the Valley that are currently using storage bags to store manure. Manure storage bags are not suitable for the typical size dairies in the Valley and there are questions about if these bags would comply with existing California regulations, including water regulations. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Liquid Manure Storage Covers** - ***(applies to all CAFs)***

The NRCS Reference Guide includes manure storage covers as a potential measure to reduce emissions from the storage of manure. Manure can be handled and stored in the form of a thick slurry, a dilute liquid, or as a solid. A study[140] notes that placing a cover over a lagoon can reduce emissions, however the different cover types have both benefits and drawbacks. Such covers include, natural or synthetic and they may be flexible or rigid, which vary in cost. The type of cover that is appropriate for each operation depends on the size and type of manure storage, environmental factors, and the goals of the farm. Manure storage covers limit emissions by slowing diffusion of gases and reducing the effects of wind on the surface of the manure. Although manure storage covers may reduce pollutants directly emitted from the manure, they do not destroy or eliminate pollutants such as ammonia. Rather, concentrations of these pollutants increase in the stored manure and additional measures would be required to prevent their release when the manure is removed from storage.

As previously mentioned, Valley dairies that handle manure as a slurry without the addition of water are extremely rare and therefore certain types of manure covers are generally not applicable. The NRCS Reference Guide notes that concrete covers cannot be used on earthen or steel manure storages and natural covers (e.g. straw, barely, cornstalks) are impractical if the surface area of the storage is very large. Dairies in the Valley primarily store liquid manure with low solids content in large earthen lagoons or ponds,[141] therefore concrete covers and natural covers cannot feasibly be used to cover liquid manure in the

[139] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-Scale Inventory of Dairy Methane Emissions in California: Implications for Mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

[140] Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

[141] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of Dairy Housing and Manure Management Practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

Valley. Additionally, the Valley regulations from the Regional Water Quality Control Board[142] and mosquito abatement districts[143] generally require the removal of any materials that would form natural covers in order to decrease the chances for the proliferation of mosquitos and other vectors.

Although covers made of rigid plastic, such as HDPE, may be a potential option to cover lagoons and ponds that store liquid manure in the Valley, they would be very prohibitively expensive because of the large area that would need to be covered. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California. Since the Valley dairies are larger compared to other dairies in the nation, the lagoons and ponds that store liquid manure are also several times larger compared to the national average dairy that stores mostly undiluted slurry manure.

Moreover, manure covers do not destroy ammonia, rather they create a barrier that suppresses emissions of ammonia from the manure and air space above the manure. This leads to increased concentrations of ammonia and other air contaminants in the manure and air space above the manure, which will just delay the release of ammonia until it is sent to a different pond or applied to land. The increase concentration of ammonia in the manure will also increase the pH and subsequently increase the potential for ammonia emissions. Furthermore, because of the warm climate of the Valley, covering a lagoon with a plastic cover would turn the lagoon into an anaerobic digester. The majority of anaerobic digesters operating on dairies in the Valley are already covered lagoon digesters. The Reference Guide also states that gases will build up under impermeable covers that must be flared or utilized in another way. Flaring or combusting these gases would produce $NO_X$, which is the primary precursor for PM2.5 in the Valley, as well as direct PM2.5 emissions.

The District has permitted several facilities to construct and operate a covered lagoon. However, in each case, the covered lagoon was part of a digester system to capture biogas/digester-gas, and the cost of the system was funded by grants from the California Department of Food and Agriculture (CDFA) Dairy Digester Research and Development Program.

In conclusion, it is not reasonable to require covers to reduce ammonia emissions from liquid manure storage in the Valley given the high expense associated to the practice and the fact that the practice is not expected to result in any overall reductions of ammonia emissions in the Valley, but could increase emissions of other pollutants.

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[142] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[143] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

**Solid Manure Storage Covers** - ***(applies to all CAFs)***

EPA identified Method 62 (Cover solid manure sources with sheeting) from the UK User Guide, noting that it could result in ammonia emission reductions up to 90 percent. Method 62 involves covering solid manure stores with sheeting, which provides a physical barrier preventing the release of ammonia to the air. EPA acknowledged that this method "would increase ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading." District Rule 4570, EPA acknowledges, contains mitigation measure options for the covering of dry manure piles, and in most cases, facilities are required to cover manure and separated solids or else remove them from the facility.[144]

Storage of solid manure/separated solids contributes a very small amount of total ammonia emissions in the Valley, by making up less than 2 percent of the total ammonia emissions from dairies. Nonetheless, covering for solid manure/separated solids during the months of October through May is included in Rule 4570 and required for most dairies during these 8 months of the year, which include the District's PM2.5 season.

Based on District permitting records covering solid manure or separated manure solids during October through May is required by 729 dairies, 84 percent of the dairies are subject to Rule 4570, and a larger percentage of the total dairy cattle since this measure is required for all dairies that are classified as large confined animal facilities under the rule.

Covers for solid manure/separated solids is not required during the summer because solid manure is primarily composed of organic material that is combustible and during the hot summers in the Valley, elevated temperatures increase the chances of spontaneous combustion of manure piles.[145] Therefore, for safety reasons manure covers cannot be required during the hotter summer months. However, through District Rule 4570, the District requires CAFs to cover solid manure/separated solids during the colder winter months, as shown below:

- Cover dry manure outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.
- Cover separated solids outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.

[144] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X*

[145] Westendorf, M. L. "Animal Science Update: Spontaneous Combustion". New Jersey Farmer. August 15, 2016. Page 6. *https://plant-pest-advisory.rutgers.edu/spontaneous-combustion/*

In conclusion, the District already has a mechanism to implement this mitigation measure for solid manure/separated solid stored onsite. No additional ammonia reductions are expected from the suggested mitigation measure.

**Allow Cattle Slurry Stores to Develop a Natural Crust** - ***(applies to dairy cattle only)***

This measure identified in the UK User Guide involves retaining a surface crust on slurry stores, composed of fiber and bedding material present in cattle slurry, for as long as possible. This practice is applicable to thick slurry manure, which differs from the typical liquid manure stored in the Valley. The dilute liquid manure handled in the Valley is stored in ponds and lagoons much larger than storages used for slurry manure in other regions, and does not contain enough solids to form a natural crust.

Additionally, this practice is more applicable to cooler climates, while in the Valley's warm climate, floating debris on liquid manure create a habitat for mosquitos and other vectors that carry diseases, including West Nile virus, zika, dengue, chikungunya, and St. Louis encephalitis.[146] To reduce the potential for the propagation of mosquitos and other disease carrying vectors, Regional Water Quality Control Board[147] and Mosquito Abatement District regulations require the removal of any dead algae, vegetation, and floating debris, including those that would form a natural crust on the surface of a lagoon or pond.[148] Thus, this practice is not allowed in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Solid-Liquid Separation** - ***(applies to all CAFs)***

The NRCS Reference Guide states that for manure streams handled as a slurry, separation of the solid and liquid portions prior to storage, additional treatment, and/or land application may reduce odor and other gaseous emissions, particularly for undersized lagoons. Various solid separation technologies are used for these purposes, including screens, rotary drums, centrifugal tanks, earthen pits, weeping walls, settling basins and screw-presses.

Dairies in the Valley primarily handle liquid manure that has been diluted with water, rather than slurry manure, and the effluent from dairies in California often has a total solids content of only 1 percent;[149] therefore this measure is not directly applicable to most dairies in the Valley. The NRCS Reference Guide indicates that solid-liquid separation does not work well for manure streams with very low or very high solids content, unless advanced technologies

[146] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

[147] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[148] Collar, C. (2005). West Nile Virus – How Dairies Can Help 'Fight the Bite. *University of California, Davis, Cooperative Extension.* Retrieved from: *https://cemerced.ucanr.edu/newsletters/September_200523148.pdf*

[149] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

or multiple separation stages or screen sizes are used to remove large and small solids from the manure stream separately. These technologies will have additional challenges and increased costs. Additionally, some studies indicate that the majority of ammonia nitrogen in dilute manure streams remains in the liquid portion and are not removed by solid-liquid separation. The NRCS Reference Guide indicates that some separator designs may increase emissions of gases or particles during the separation process. Dried separated solids may also increase the potential for PM emissions.

As mentioned above, this control measure is applicable to manure handled as a slurry rather than the dilute liquid manure that is typically handled on dairies in the Valley. Therefore, this practice is not directly applicable to dairies in the Valley. However, for cattle facilities that handle liquid manure, Rule 4570 does allow the facilities to choose the option to remove solids from the waste system with a solid separator system prior to the waste entering the lagoon. This option has been chosen by the vast majority cattle facilities that handle liquid manure, including over 90 percent of dairy cattle facilities subject to Rule 4570.[150] The option in Rule 4570 is as follows:

- Remove solids from the waste system with a solid separator system, prior to the waste entering the lagoon.

In conclusion, the District already has a mitigation measure option to minimize emissions from solid-liquid manure separation. No additional ammonia reductions are expected from the suggested mitigation measure.

**Anaerobic Digesters** - ***(applies to dairy cattle only)***

Anaerobic digesters are storage or treatment lagoons that are undergoing anaerobic reactions, primarily located at dairies. Digesters are outfitted with roofs and covers that enclose all anaerobic emissions within the system and vent to a gas collection system that eliminates undesired methane emissions. The microbes performing anaerobic reactions in lagoons convert nitrogen to form various new compounds, including ammonia. Through the implementation of its Short-Lived Climate Pollutant Strategy and SB 1383,[151] the State of California has funded the installation of over 120 dairy digester systems throughout the state to reduce methane emissions, with the majority of installations in the San Joaquin Valley. Through the generation of vehicle renewable natural gas, some dairy digester systems have the potential of reducing vehicle-related NOx, PM2.5, air toxics, and greenhouse gas (GHG) emissions.

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[150] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[151] CARB. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. (March 2022). Retrieved from: *https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiayMXd4af9AhXWrmoFHYf2BNsQFnoECBAQAQ&url=https%3A%2F%2Fww2.arb.ca.gov%2Fsites%2Fdefault%2Ffiles%2F2022-03%2Ffinal-dairy-livestock-SB1383-analysis.pdf&usg=AOvVaw32GB5_r8-3GsSd57-XTnyo*

Some forms of energy conversion from biogas (e.g., burning biogas in an engine to produce electricity) may increase emissions of NOx, a precursor for PM2.5 and ozone, and direct PM2.5 emissions. These emissions can have a negative impact in the Valley, which is designated as nonattainment for PM2.5 and ozone This technology is very expensive, due to capital costs, operation, and maintenance expenses. It also requires significant addition of water, and may not be feasible in water-limited areas.

The NRCS Reference Guide includes anaerobic digesters as a measure to reduce VOCs and GHG emissions, but does not indicate that it reduces ammonia. Some of the information discussed in the NRCS Reference Guide about anaerobic digestion indicates a potential for increased ammonia emissions. The results of some studies also indicate that there is a potential for increased ammonia emissions following digestion.[152] There is limited information regarding the potential and scale of ammonia emissions impacts associated with digester, and California does not currently attribute any increased ammonia impacts from the implementation of dairy digester systems.

At this time there are significant uncertainties about the overall effect of anaerobic digesters on ammonia emissions from manure and additional research is needed to better understand this, particularly for digesters in the Valley. Because of this and the very high costs associated with installation of anaerobic digesters, they are not a feasible option to implement into Rule 4570 at this time. However, this practice would be evaluated as a potential BACT measure for any new or expanding operations; the required mitigation measure from BACT Guideline 5.8.6[153], is as follows:

- Anaerobic treatment lagoon designed according to NRCS Guideline 359.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new confined animal facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

**<u>Manure Additives</u> - *(applies to all CAFs)***

Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps.[154] For slurry and liquid manure, it is difficult and costly to apply a

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[152] Koirala, K., Ndegwa, P.M., Joo, H.S., Frear, C., Stockle, C.O., Harrison, J.H. (2013). Impact of Anaerobic Digestion of Liquid Dairy Manure on Ammonia Volatilization Process. *American Society of Agricultural and Biological Engineers,* Vol. 56(5): 1959-1966. Retrieved from: *https://labs.wsu.edu/ndegwa/documents/2016/09/Article-57.pdf/*

[153] CARB BACT Guidelines Tool. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID781.pdf?:linktarget=_self&:embed=yes

[154] USDA NRCS/EPA (2017) Agricultural Air Quality Conservation Measures Reference Guide for Poultry and Livestock Production Systems. *https://www.nrcs.usda.gov/sites/default/files/2022-06/Ag_AQ_Conservation_Measures_Poultry_and_Livestock_September_2017.pdf*

sufficient amount of amendments to change the pH of the manure because of its natural buffering capacity, or resistance to changes in pH due to its chemical properties.

The NRCS Reference Guide states, *"It is often difficult to establish microbiological additives due to competition from naturally-occurring bacteria in manure."* The microbes in microbial additives are often out-competed by the naturally occurring microorganisms, because of the abundance of diverse microorganisms that are naturally present in manure that can multiply rapidly when favorable conditions are present. As a result, microbial additives are often ineffective or must be continually added to the manure. A study[155] conducted by Iowa State University, clearly demonstrates that many questions remain unanswered about the general effectiveness of microbial additives used to reduce emissions. The study evaluated 12 commercial microbial additives that were marketed for their ability to reduce emissions of odorous VOCs, H2S, ammonia, GHG, and odors. The results indicated that emissions from the treated manure were not statistically significant to the untreated manure for any of the 12 products tested. Thus, the ability of microbial additives to reduce emissions from manure remains unproven. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium** - ***(applies to all CAFs)***

This mitigation method mentioned in the compilation by Guthrie, et al.[156] involves the use of manure amendments to minimize ammonia emissions. Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps. For slurry and liquid manure, it is difficult and costly to apply a sufficient amount of amendments to change the pH of the manure because of natural buffering capacity. Notably, some additives can even increase emissions of certain pollutants and can be toxic to handle.

Moreover, any additives to the manure require approval of the Water Quality Control Board.[157] The Water Quality Control Board has determined that increased salinity is a threat

[155] Koziel, J., Chen, B., Andersen, D., Parker, D., Bialowiec, A., Banik, C., Lee, M., O'Brien, S., Ma, H., Meiirkhanuly, Z., Wi, J., Li, P., Iowa State University. (2021). Evaluating Manure Additives for Odor Mitigation. *National Hog Farmer*. Retrieved from: *https://www.nationalhogfarmer.com/agenda/evaluating-manure-additives-odor-mitigation*

[156] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[157] California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

to water quality in the Valley.[158] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

For reasons discussed above, manure amendments are not practical for most operations in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Acidifying Amendments and Additives for Poultry Litter** - ***(applies to poultry only)***

This method involves the application of aluminum to poultry litter to reduce the pH of the litter. However, poultry operations have already reduced nitrogen excretion by 55 percent and are not a significant source of ammonia in the Valley. Use of acidifying litter amendments is more common for poultry litter however, any additives to the manure require approval of the Water Quality Control Board. The Water Quality Control Board has determined that increased salinity is a threat to water quality in the Valley.[159, 160] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

Notably, some additives can increase emissions of certain pollutants and can be toxic to handle. For example, the litter in poultry houses in the Valley are drier than many other parts of the country and therefore aluminum would need to be applied as a liquid. Nevertheless, liquid aluminum is an acid that is dangerous to handle and requires a certified applicator to be hired which results in higher costs.

Despite the uncertainties above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

Ammonia is a weak base and reducing the pH of litter binds ammonia and reduces its volatilization. Aluminum sulfate, also known as alum, is a common compound used to treat poultry litter to reduce ammonia emissions and bind phosphorous to prevent runoff. The typical recommended application rate for aluminum sulfate is 0.1 to 0.2 lb of aluminum sulfate per broiler placed.[161] The higher the aluminum sulfate application rate, the higher the ammonia control and phosphorus binding ability of aluminum sulfate. The lower recommended application rate will control ammonia emissions for about half the time as the

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[158] California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

[159] California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

[160] California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

[161] See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*

higher recommended application rate.[162, 163] Young chicks are more vulnerable to higher ammonia concentrations in the houses; however, ammonia emissions are lower because of the lower amount of manure produced by the smaller birds. These recommended application rates are based on broilers with a finished weight of approximately four pounds. Larger birds will require correspondingly larger application rates to achieve the same control of ammonia.[164]

A study published in 2020 found that an application rate of 98 kg of aluminum sulfate per 100 square meters incorporated into litter reduced overall ammonia emissions from broilers by 35 percent.[165] In the study, the birds were placed in 2.1 m by 1.8 m pens with 50 birds per pen to evaluate different treatments. Therefore, the application rate of alum on a per bird basis was calculated as follows:

98 kg/100 $m^2$ x 2.1 m × 1.8 m ÷ 50 bird = 0.074 kg/bird

The application rate of 0.074 kg/bird is equivalent to an application rate 0.16 lb-aluminum sulfate per bird. Therefore, it will be assumed that this is the application rate required to reduce ammonia emissions by 35 percent. The District's current ammonia emission factor for broiler chickens is 0.0958 lb-NH3/bird-year. Thus, the ammonia emission reductions for this practice can be calculated as follows:

0.0958 lb-NH3/bird-year x 35% = 0.0335 lb-NH3/bird/year

The cost of the emission reductions is based on the cost of the purchase and application of aluminum sulfate. Because of the typically dry conditions in the Valley, liquid aluminum sulfate is preferred because moisture is required for aluminum sulfate to react with ammonia. A USDA-ARS publication[166] indicates that one ton of aluminum sulfate is equivalent to 370 gallons of liquid aluminum sulfate. Based on a web search, the price of aluminum sulfate is estimated to be $1,155 per 55 gallon drum.[167] The customer applicator rate is assumed to be

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162 Moore, P., Watkins, S. Treating Poultry Litter with Alum. University of Arkansas (U of A) Division of Agriculture Cooperative Extension Service. *https://www.uaex.uada.edu/publications/PDF/FSA-8003.pdf*

163 Moore, P., Miles, D., Burns, R. (March 2019). Reducing Ammonia Emissions from Poultry Litter with Alum. Livestock and Poultry Environmental Learning Community (LPELC). *https://lpelc.org/reducing-ammonia-emissions-from-poultry-litter-with-alum/*

164 Anderson, K.; Moore, P.A., Jr.; Martin, J.; Ashworth, A.J. (2020) Effect of a New Manure Amendment on Ammonia Emissions from Poultry Litter. *Atmosphere*, *11*, 257. *https://doi.org/10.3390/atmos11030257*

165 Penn, C., Zhang, H (April 2017) Alum-Treated Poultry Litter as a Fertilizer Source. Oklahoma State University Extension. *https://extension.okstate.edu/fact-sheets/alum-treated-poultry-litter-as-a-fertilizer-source.html#nitrogen-content-of-alum-treated-litter*

166 See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*

167 Alliance Chemical, Price of Aluminum Sulfate 50%. Retrieved from: *https://alliancechemical.com/product/aluminum-sulfate-50/?attribute_pa_size=55-gallon&attribute_pa_packaging-type=drum&gclid=EAIaIQobChMIurHTv9WT_QIVMRPUAR1c5QvKEAQYASABEgJ5__D_BwE*

$100 for each broiler house housing 20,000 birds. Therefore, the total cost for each application of aluminum sulfate on a per bird basis is calculated as follows:

0.16 lb-aluminum sulfate/bird x 1 ton/2,000 lb x 370 gal-aluminum sulfate/ton-aluminum sulfate x $1,155/55 gal-aluminum sulfate + $100/20,000 bird = $0.63/bird

Approximately 6.7 broiler flocks are produced each year and aluminum sulfate must be applied prior to placing each flock; therefore, the annual cost of this measure on a bird capacity basis is 6.7/year x $0.63/bird = $4.22/bird capacity-year.

The cost effectiveness of the ammonia reductions from this measure are calculated as follows:

$4.22/bird-year ÷ 0.0335 lb-NH3/bird-year x 2,000 lb/ton = $251,940/ton-NH3 reduced

As demonstrated above, the potential reductions from this measure are not cost effective, with a cost effectiveness of $251,940 per ton of ammonia reduced. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Urease Inhibitors** - ***(applies to all cattle)***

A study[168] indicates that the information for this control measure was taken from AirControlNet, a software tool previously used by EPA to estimate the cost of emission reductions. The AirControlNET v.4.1 Documentation Report[169] indicates that the specific chemical additive that this measure refers to was N-(n-butyl) thiophosphoric triamide (NBPT), which was being sold under the trade name Conserve-Nr. NBPT is a type of urease inhibitor. The cost information was provided by a supplier of the chemical and appears to be an underestimate.

Urease inhibitors inhibit the action of the enzyme urease. Urease, which is present in feces and produced by soil microorganisms, converts urea into ammonia, which can then volatilize. Although there are many compounds that can inhibit urease, only a few are non-toxic, effective at low concentrations, and chemically stable. Urease inhibitors have shown promising results for reducing nitrogen emissions from urea-based fertilizers, but some studies indicate that there remain questions about their effectiveness in reducing ammonia from manure.[170]

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[168] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[169] E.H. Pechan & Associates, Inc. (September 2005). AirControlNET v.4.1 Documentation Report. Retrieved from: *https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1012ZYW.TXT*

[170] Lasisi, A.A., Akinremi, O.O., and Kumaragamage, D. "Ammonia emission from manures treated with different rates of urease and nitrification inhibitors," Canadian Journal of Soil Science 100(3), 198-205, (25 February 2020). Retrieved from: *https://doi.org/10.1139/cjss-2019-0128*

Urease inhibitors appear to reduce ammonia emissions for relatively short periods of time and must be reapplied, and the buildup of urea in the pen surface may require that the NBPT additions increase with time to continue to control ammonia. Because of the need to re-apply increasing amounts of urease inhibitors as manure and urea accumulate, there will be increased costs.

Additionally, there is evidence that urease inhibitors may alter plant metabolism and lead to accumulation of urea in plant tissue,[171] which can have negative effects on crops. Urea inhibitors will also increase the amount of nitrogen in the manure, and to comply with Water Quality Control Board Regulations, some farms would need to acquire additional cropland to apply the manure or identify ways to export the manure to ensure that nitrogen is not over-applied.

It appears that the treatment of animal manure with urease inhibitors has not yet been commercialized. This is likely because of the limited chemical stability of the inhibitors, the need for reapplication, the lack of efficient and automated application systems, and a subsequent increase in the cost for the farmer. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Surface Cooling of Slurry Manure - *(applies to all CAFs)***

The publication by Guthrie, et al.[172] suggests this measure for CAFs with a slurry manure handling system. The measure involves lowering the temperature of the slurry in the channels by pumping a coolant (e.g., groundwater) through a series of fins floating on the slurry. This measure appears to be largely theoretical, and the District is not aware of any instances in which cooling of liquid or slurry manure has been used to reduce emissions from animal production operations. Furthermore, there are high costs for installation of piping and pumping coolant and circulation of coolant through manure, and recycling groundwater may not be permitted in some regions. For these reasons, this measure is unproven and not feasible to implement in the Valley.

**Feeding Strategies to Lower the pH of Manure - *(applies to all CAFs)***

Livestock feeding strategies can influence the pH of manure and urine. The pH of manure can be lowered by increasing the fermentation in the large intestine. This increases the volatile fatty acids (VFA) content of the manure and causes a lower pH. The pH of urine can be lowered by lowering the electrolyte balance of the diet. Furthermore, the pH of urine can be lowered by adding acidifying components to the diet. A low pH of the manure and urine

[171] Zanin L, Venuti S, Tomasi N, Zamboni A, De Brito Francisco RM, Varanini Z, Pinton R. (2016) Short-Term Treatment with the Urease Inhibitor N-(n-Butyl) Thiophosphoric Triamide (NBPT) Alters Urea Assimilation and Modulates Transcriptional Profiles of Genes Involved in Primary and Secondary Metabolism in Maize Seedlings. Front Plant Sci. 2016 Jun 22;7:845. doi: 10.3389/fpls.2016.00845. PMID: 27446099; PMCID: PMC4916206.
[172] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

excreted also results in a low pH of the slurry/manure during storage even after a certain storage period. This pH effect can reduce ammonia emissions from slurries during storage and also following application. This measure is primarily for non-ruminants, such as poultry and pigs and is not recommended for cattle.

The pH of freshly excreted urine mainly depends on the electrolyte content of the diet. The pH of urine will eventually rise towards alkaline values due to the hydrolysis of urea irrespective of initial pH; however, the initial pH and the pH buffering capacity of urine affect the rate of ammonia volatilization from urine immediately following urination. Lowering the pH of urine of ruminants is theoretical possible. However, it has not been demonstrated to be feasible on actual farms. Lowering the pH of cattle manure is also theoretically possible, but this might easily coincide with disturbed rumen fermentation and is therefore not recommended. Since this measure has not been demonstrated for cattle and remains theoretical, it is premature to consider it as part of any regulatory efforts.

The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

## Land Application of Manure

**Table 11: Land Application of Manure Measures Evaluated**

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Timing of Land Application | Timing of Land Application | All Cattle | NRCS[173] |
| | Optimal Weather Conditions for Spreading | All Cattle | Guthrie[174] |
| Injection | Injection | All Cattle | NRCS |
| | Use Slurry Injection Application Techniques | All Cattle | Price[175] |
| | Injector | All Cattle | Guthrie |

[173] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[174] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[175] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | Open-slot Injection | All Cattle | Webb[176] |
| | Injector | All Cattle | Eory[177] |
| | Injection Techniques | All Cattle | Bittman[178] |
| | Injection into the Soil | All Cattle | Preece[179] |
| Incorporation of Liquid and Solid Manure | Incorporation | All Cattle | NRCS |
| | Incorporate Manure into the Soil | All Cattle | Price |
| | Incorporation of Manure | All Cattle | Guthrie |
| | Incorporation of Surface-Applied Solid Manure and Slurry into Soil | All Cattle | Bittman |
| | Incorporation into the Soil | All Cattle | Preece |
| | Incorporate Manure into the Soil | All Cattle | Atia[180] |

[176] Webb, J., Pain B., Bittman, S., Morgan J. The impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—a review. Agric. Ecosyst. Environ. 137, 39–46 (2010). Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0167880910000046?via%3Dihub*

[177] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

[178] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds), 2014, "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[179] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[180] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| | Immediate Incorporation of Applied Manure | All Cattle | Pinder[181] |
| Band Spreading | Banding | All Cattle | NRCS |
| | Slurry Band Spreading Application Techniques | All Cattle | Price |
| | Band Spreading | All Cattle | Guthrie |
| | Band Spreading Slurry | All Cattle | Bittman |
| Other Land Application | Slurry Dilution | All Cattle | Bittman |
| | Transport Manure to Neighboring Farms | All Cattle | Price |

**Timing of Land Application** - ***(applies to all cattle)***

This measure requires operators to apply the correct amount of necessary nutrients to crops when they are most in demand and in locations where they can be accessed by specific plants. Applying nutrients in spring prior to planting, when crops are ready to utilize the nitrogen, can reduce ammonia emissions compared to applying in fall. Applying at lower soil temperatures can also help to reduce near-term ammonia emissions due to reduced microbial activity in cooler soils. Split application to better time the nutrient application to crop needs can also be beneficial.

Although not specifically included in Rule 4570, the measure is already required for confined animal facilities in the Valley that apply manure to land. California Regional Water Quality Control Board regulations[182] require that manure may only be applied to land at agronomic rates in accordance with an approved nutrient management plan, and that nutrients, including nitrogen, may only be applied at times when plants can utilize these nutrients. The rate of application of manure and process wastewater for each crop in each land application area (also considering sources of nutrients other than manure or process wastewater) to meet each crop's needs without exceeding the application rates is specified in the Regional Water Quality Control Board Technical Standard.

[181] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[182] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

The NRCS Reference Guide estimates that this measure will reduce ammonia emissions from land application by 65-70 percent. Because this measure is already required, as an industry standard, these reductions have already been achieved in the Valley.

**Injection** - ***(applies to all cattle)***

Applying manure to the soil surface without incorporation can lead to significant emissions of ammonia and other odorous gases. Several of the mitigation measure compilations evaluated by the District included injection of liquid or slurry manure as an option to reduce ammonia emissions from land application. However, this method is more applicable to slurry manure than the dilute liquid manure applied to land in the Valley. Additionally, the equipment needed to transport and inject the dilute liquid manure, which is not typically used in the Valley, would have high costs for fuel and would increase emissions of NOx and PM2.5.

Estimated ammonia emissions reductions from the injection of liquid manure are based on the assumption that surface broadcasting of liquid manure is the typical practice. Broadcasting of liquid manure results in higher emissions because of the larger amount of surface area of the liquid manure that will be in direct contact with the atmosphere. However, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting. A report prepared by the University of California Division of Agricultural and Natural Resources Committee of Experts on Dairy Manure Management[183] indicates that in California, "nearly all" manure from lagoons is diluted with irrigation water and applied via surface gravity irrigation systems and that "during irrigations, farmers commonly dilute lagoon water with 5 to 10 parts of fresh source water." The report goes on to state that "in systems with frequent, but well diluted manure water applications, ammonia losses from the ground surface will commonly be minimal during the irrigation (10 percent or less)." The Ammonia Volatilization from Manure Application fact sheet,[184] estimates that ammonia losses from unincorporated manure to be 66 percent in the spring and early fall; this the standard practice in the Valley of applying manure by gravity flow irrigation is already estimated to reduce ammonia emissions by at least 85 percent compared to broadcasting of manure.

Furthermore, to avoid damaging growing crops, injection of liquid manure can only be performed prior to planting the crop, typically a maximum of two times per year.

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[183] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

[184] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

Additionally, the amount of nitrogen that can be applied to cropland is limited to protect water quality. Many agricultural areas in the Valley already have nitrate levels in the groundwater that are above acceptable limits, and many dairies are required to reduce the amount of nitrogen applied to land. Injection of manure reduces the amount of nitrogen emitted to the air, but the retained nitrogen is placed in the soil. Thus, injection of manure into the soil will increase the amount of nitrogen in the cropland and may not be feasible for some dairies, or will require additional land in order to comply with their nutrient management plans.

District Rule 4570 includes the requirement to minimize the amount of emissions from applying liquid manure to the soil. These mitigation measures include an option to inject liquid manure, as shown below:

- Apply liquid/slurry manure via injection with drag hose or similar apparatus

In conclusion, the District already has mitigation measures for liquid manure injection. No additional ammonia reductions are expected from the suggested mitigation measures.

**Incorporation of Liquid Manure** - ***(applies to all cattle)***

Many mitigation measure compilations included incorporation of slurry and liquid manure into soil as an option to reduce ammonia emissions.[185] However, as discussed above, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, ammonia emissions from the application of liquid manure in the Valley is already much lower than the emissions from broadcasting slurry manure.

Slurry manure is not typically applied in the Valley and liquid manure in the Valley is diluted prior to application. However, District Rule 4570 includes a mitigation option to minimize the amount of emissions from incorporating liquid manure to the soil, as shown below:

- Allow liquid manure to stand in the fields for no more than 24 hours after irrigation.

In conclusion, the District already has mitigation measures for the incorporation of liquid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

**Incorporation of Solid Manure** - ***(applies to all cattle)***

The NRCS Reference Guide and UK User Guide include methods for incorporation of solid manure that involve mixing manure with surface soil to reduce the exposed surface area of the manure. The reference guide advises that incorporation should occur as soon as possible

[185] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

after the manure is applied, or at least within 24 hours, to reduce ammonia emissions. In the Valley, solid manure land application accounts for less than 3 percent of total ammonia emissions from dairies and incorporation of solid manure within 72 hours is already required for over 80 percent of cattle facilities that apply manure to land.

To avoid damaging growing crops, incorporation of solid manure can only be performed prior to planting the crop, typically a maximum of two times per year. Almost all dairies in the Valley use a double-crop farming system for their cropland to maximize the amount of manure that can be applied and increase the amount of feed produced for the cattle, with some dairies using a triple-crop system. In the typical double-crop system used on Valley dairies, corn for silage is planted in late April through June to be harvested in September, and winter forage (e.g. wheat, oats, barley, etc.) is planted in late September to be harvested in April or May.[186,187] Because of the very short time frame available between crops, the standard practice in the Valley is to incorporate applied solid manure as soon as practical so the land can be prepared for the next crop.

Solid manure applied to cropland is often incorporated immediately after application; however, additional time may sometimes be required due to unforeseen circumstances, such as difficult weather conditions, equipment breakdowns, or the unavailability of the contractors that perform the work since they may be busy at other farms that are also preparing to plant the next crop. With this under consideration, Rule 4570 gives additional time to account for the unforeseen circumstances that may unexpectedly delay incorporation of manure into cropland within 24 hours, as shown below:

- Incorporate all solid manure within 72 hours of land application.

The District is further evaluating requiring solid manure applied to cropland to be incorporated within 24 hours. An analysis of this measure, including the control efficiency and estimated costs, is below.

The control efficiency for incorporation is estimated based on information from the Chesapeake Bay Program Watershed Model report.[188] This report includes estimations of ammonia emission reductions for low-disturbance incorporation and high-disturbance incorporation of manure. The report gives vertical tillage as an example of low-disturbance incorporation and states that for high-disturbance incorporation, chisel plowing followed by

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[186] University of California, Davis. UC Drought Management – Corn. Retrieved from: *https://ucmanagedrought.ucdavis.edu/Agriculture/Crop_Irrigation_Strategies/Corn/*

[187] Ag Proud – Progressive Dairy. 12-Month Forage Pays. Retrieved from: *https://www.agproud.com/articles/30676-12-month-forage-pays*

[188] Chesapeake Bay Phase 6.0 Manure Incorporation and Injection Expert Review Panel: Dell, C., Allen, A., Dostie, D., Meinen, R., Maguire, R (December 2016) Manure Incorporation and Injection Practices for Use in Phase 6.0 of the Chesapeake Bay Program Watershed Model. Prepared for Chesapeake Bay Program, Annapolis, MD 21403. CBP/TRS-309-16. EPA Contract No. EP-C-12-055. *https://d18lev1ok5leia.cloudfront.net/chesapeakebay/documents/Phase_6_FINAL_MII_Final_Report.pdf*

secondary tillage with a disk harrow or field cultivator is expected to be the most common practice. Information in the report indicates that with low-disturbance incorporation, ammonia emissions are reduced 34 percent when manure is incorporated within 72 hours and 50 percent when manure is incorporated within 24 hours. The report also indicates that with high-disturbance incorporation, ammonia emissions are reduced 50 percent when manure is incorporated within 72 hours and 75 percent when manure is incorporated within 24 hours. Based on this information, the ammonia (NH3) emissions from incorporation of solid manure within 72 hours and 24 hours are estimated as follows:

<u>Low-Disturbance Incorporation of Solid Manure within 72 Hours</u>

Control Efficiency: 34%

Percent NH3 emissions of manure that is not incorporated: 66%

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

<u>High-Disturbance Incorporation of Solid Manure within 72 Hours</u>

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

<u>High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

Control Efficiency: 75%

Percent NH3 emissions of manure that is not incorporated: 25%

The ammonia control efficiency for incorporation of solid manure within 24 hours rather than 72 hours, compared to the ammonia emissions from solid manure that is not incorporated is estimated as follows:

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

66% - 50% = 16%

<u>High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

75% - 50% = 25%

The ammonia emissions from solid manure land application are approximately 2.8 percent of the ammonia emissions from dairies and other cattle facilities; therefore, the overall control efficiency of this measure is estimated to be:

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

17% x 2.8% = 0.48% of total NH3 emissions from cattle

High-Disturbance Incorporation of Solid Manure within 24 Hours

25% x 2.8% = 0.7% of total NH3 emissions from cattle

The incremental ammonia control efficiency for incorporation of solid manure within 24 hours compared to incorporation of solid manure within 72 hours is calculated as follows.

Low-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/66%) = 24.2%

High-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/75%) = 33.3%

This control efficiency is just for the application of solid manure to cropland, which is a very small portion of the total emissions from cattle facilities.

The cost of more rapid incorporation varies greatly, depending whether a farm already has the required equipment available or if the farm requires an additional tractor and must contract with a custom farm service to implement this practice. For farms for which the required equipment for more rapid incorporation is available, it will be assumed that the primary cost of this measure will be the additional labor required to operate the equipment, to ensure that the manure is incorporated within the required timeframe. For other farms for which the required equipment is not available, it will be assumed that they must hire a custom farm service to ensure that manure is incorporated within the required timeframe. The labor costs for incorporation of solid manure and the costs for hiring a custom farm service will be estimated based on information from the University of California Cooperative Extension.[189, 190] The costs for labor and hiring a custom farm service for low-disturbance incorporation of solid manure are assumed to be similar to finish discing of a field, and the costs for labor and hiring a custom farm service for high-disturbance incorporation of manure are assumed to be similar to chiseling a field followed by discing.

Based on the University of California Cooperative Extension publications, the incremental cost for low-disturbance incorporation of solid manure is estimated to be approximately $2.64 per acre if only additional labor is required, and $15.37 per acre if a custom farm service must be used. At dairies in the Valley, solid manure is typically applied to land twice per year so the overall cost for low-disturbance incorporation of solid manure is as follows:

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[189] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 300 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/1c/e2/1ce256d0-957e-4bd4-b17e-18fef4efcedd/16alfalfasjv300acfinal_41916.pdf*

[190] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 50 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/24/b6/24b68b4a-4c04-4853-b127-d3461e1a248f/16alfalfasjv50ac_final_4192016.pdf*

Incremental Labor Cost for Low-Disturbance Incorporation of Solid Manure within 24 Hours

\$2.64/acre x 2 time/year = \$5.28/acre-year.

Incremental Cost for Custom Farm Service for Low-Disturbance Incorporation of Solid Manure within 24 Hours

\$15.37/acre x 2 time/year = \$30.74/acre-year.

Based on the University of California Cooperative Extension publications, the incremental cost for high-disturbance incorporation of solid manure is estimated to be approximately \$6.60 per acre if only additional labor is required, and \$64.21 per acre if a custom farm service must be used. As mentioned above, at dairies in the Valley solid manure is typically applied to land twice per year so the overall cost for high-disturbance incorporation of solid manure is as follows:

Incremental Labor Cost for High-Disturbance Incorporation of Solid Manure within 24 Hours

\$6.60/acre x 2 time/year = \$13.20/acre-year.

Incremental Cost for Custom Farm Service for High-Disturbance Incorporation of Solid Manure within 24 Hours

\$64.21/acre x 2 time/year = \$128.42/acre-year.

Estimated ammonia emissions from unincorporated manure will be based on measurements included in the 2008 Dairy Emission Study report by Schmidt.[191] Based on measurements in this study, ammonia emissions from unincorporated solid manure are estimated to be approximately 4 lb-NH3/acre-year.

The cost effectiveness of the potential ammonia reductions for low-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 72 hours:

4 lb-NH3/acre-year x 66% = 2.64 lb-NH3/acre-year

NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 24 hours:

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

Potential NH3 Emission Reductions for Low-Disturbance Incorporation within 24 hours

= 2.64 lb-NH3/acre-year - 2.0 lb-NH3/acre-year = 0.64 lb-NH3/acre-year

[191] Schmidt, C., Card, T. (August 2009) 2008 Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Prepared for the San Joaquin Valleywide Air Pollution Study Agency

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $5.28/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $16,500/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $30.74/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $96,063/ton-NH3

The cost effectiveness of the potential ammonia reductions for high-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 72 hours:

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 24 hours:

4 lb-NH3/acre-year x 25% = 1.0 lb-NH3/acre-year

Potential NH3 Emission Reductions for High-Disturbance Incorporation within 24 hours

= 2.0 lb-NH3/acre-year - 1.0 lb-NH3/acre-year = 1.0 lb-NH3/acre-year

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $13.20/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $26,400/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $128.42/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $256,840/ton-NH3

As explained above, cattle facilities that apply solid manure to cropland incorporate the manure as quickly as possible in order to prepare for planting of the next crop; so this is already an industry standard, therefore, many cattle facilities are already attaining the potential ammonia emission reductions of this practice, except when conditions make this impractical.

In conclusion, the District already has mitigation measures for incorporation of solid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

**<u>Band Spreading</u> - *(applies to all cattle)***

This practice[192] reduces volatilization of ammonia by using low-pressure application near the ground. Band spreading of manure can only be done during very limited periods immediately prior to planting of a crop, a maximum of two times per year. This practice is primarily applicable to slurry manure rather than flush manure, and has limited applicability to the Valley in which most manure is applied as a liquid or a solid. Band spreading is generally a slower operation (with lower application rates), so there may be some issues with labor availability. Additionally, there are high costs due to the initial investment of new machines, as well as the costs of ongoing maintenance and fuel.

As previously discussed, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation, which allows manure to flow on the ground without using pressure to apply liquid manure. Due to the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting and also expected to be lower than emissions from liquid manure applied with band spreading. Moreover, trucks used for these methods would damage growing crops and directly emit NOx and PM, hindering the District's efforts to attain the PM2.5 and ozone national ambient air quality standards (NAAQS). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**<u>Slurry Dilution</u> - *(applies to all cattle)***

This method involves the dilution of slurry with water to decrease the ammonium-N concentration, as well as increase the rate of infiltration into the soil following spreading on land. For undiluted slurry, dilution must be at least 1:1 (one part slurry to one part water) to reduce emissions by at least 30 percent.

This practice is applicable to manure handled as a slurry. The slurry manure would be diluted by 50 percent so it can be infiltrated into soil more quickly. The ammonia reductions for this measure are proportional to the extent of dilution. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. The typical practice in the Valley is to dilute manure with irrigation water when it is applied to cropland. The liquid handled on Valley dairies typically has a DM content of 2 percent or less. This manure is then commonly further diluted with 5 to 10 parts of fresh source water during irrigation. Because of this, ammonia emissions from the typical application of liquid manure can be estimated to be more than 90 percent lower than the ammonia emissions from this practice (4.5 percent DM applied,

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[192] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

compared to 0.2 percent DM applied). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Transport Manure to Neighboring Farms** - ***(applies to all cattle)***

This mitigation measure does not result in overall decreases in ammonia emissions. Although ammonia emissions are reduced from the exporting farm, these emissions are transferred to the receiving farm.

Regional Water Quality Control Board regulations prohibit the over-application of nutrients from manure in the Valley and already only allow manure to be applied at agronomic rates in accordance with an approved nutrient or waste management plan. Nutrient management plans require that farms transport excess manure to other fields or identify other uses for excess manure. Transporting manure would increase emissions of NOx and PM2.5 from fuel use, and these emissions would hinder the District's efforts to attain the PM2.5 and ozone NAAQS. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

## Other Mitigation Measures

**Table 12: Other Mitigation Measures Evaluated**

| Method | Measure | CAF Type | Reference |
|---|---|---|---|
| Other | Pasture and Range Management: Stocking Density | Other Cattle | NRCS[193] |
| | Improved Livestock Genetics | All | Price[194] |
| | Planting a Tree Shelter Belt | All | Guthrie[195] |
| | Using Plants with Improved Nitrogen Use Efficiency | All Cattle | Guthrie |
| | Changing Land from Arable to Woodland | All | Guthrie |
| | Reduced Consumption of Meat and Eggs by Humans | All | Guthrie |

**Pasture and Range Management: Stocking Density** - ***(applies to grazing cattle only)***

The NRCS Reference Guide lists managing animal stocking density at grazing-based livestock operations as a mitigation method for ammonia emissions. However, the District does not have authority to regulate animals on pasture or rangeland, as they are not confined. This measure also does not recommend a specific stocking density; however, cattle that graze on pastureland and rangeland in California generally require low stocking densities to provide sufficient forage for cattle. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

[193] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[194] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*
[195] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

**<u>Improved Genetics</u> - *(applies to all CAFs)***

A publication prepared for use in the United Kingdom includes genetic selection of useful traits to improve animal health and fertility as a potential mitigation measure to increase the efficiency of animals and reduce environmental impacts. Farmers select animal breeds that have improved genetics that increase efficiency as feasible to reduce overall costs and increase yield. The publication notes that use of animals with improved genetics "*is generally good in the poultry, dairy and pig industries*." Improvements in genetics and management practices to increase efficiency have already significantly reduced the environmental footprint of production from animal agriculture compared to previous years. As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent and water use has decreased by 65%.[196] GHG emissions from California dairy cattle per amount of milk produced have also decreased by over 45 percent in the 50 years from 1964 to 2014.[197] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent, primarily due to the reduced time from egg to market age.[198]

Farmers are expected to continue to use animals with improved genetics that will increase efficiency and reduce production costs. However, there are several issues that cause this measure to be unsuitable as a requirement in a regulation. The study does not specify the genetic traits that need to be improved. The measure is largely theoretical and requires extensive research and funding to develop new breeds with the desired traits. It would take generations of each breed to evaluate the effectiveness of the breeds as it pertains to reducing ammonia emissions and any potential adverse impacts on the environment. There are also potential ethical concerns regarding if animals were to be genetically modified to accelerate selection of specific traits. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**<u>Planting a Tree Shelter Belt</u> - *(applies to all CAFs)***

This measure involves planting tree shelterbelts around livestock housing and manure slurry storage facilities to disrupt airflow around these sites. The effectiveness of tree shelterbelts as a measure to reduce particulate matter from facilities depends on the shelterbelt height, canopy density, and the prevailing environmental conditions. While some evidence demonstrates effectiveness for PM2.5 emissions reductions, there is little to no evidence for

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[196] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[197] Naranjo A., Johnson A., Rossow H., Kebreab E. (2020) Greenhouse Gas, Water, and Land Footprint per Unit of Production of the California Dairy Industry Over 50 years. J Dairy Sci. 2020 Apr;103(4):3760-3773. doi: *10.3168/jds.2019-16576*. Epub 2020 Feb 7. PMID: 32037166.

[198] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

ammonia emissions reductions. Effective tree shelterbelts are expensive and difficult to establish due to the large size of the facilities, severe water limitations, soil conditions, and the number of trees needed to protect these areas.

Irrespective of the lack of available data on the potential ammonia emissions reductions, implementation of this measure requires additional consideration with respect to animal health. Cattle facilities in the Valley depend on natural airflow to cool cattle and provide them with fresh air. Disrupting natural airflow can adversely affect cattle that depend on the natural flow of air, particularly during summer months where large numbers of heat-related animal mortalities occur in the San Joaquin Valley. Tree shelterbelts also require sufficient space to be effective, thus, dairies would need either to remove crops or acquire additional land for a shelterbelt. Furthermore, a shelterbelt of sufficient height to be effective would take a number of years to establish. In many cases in the Valley, where the soil has high salinity, conditions are unsuitable for planting tree shelterbelts.

In several cases, permitted CAFs proposed to grow shelterbelts to satisfy District BACT requirements, however, the shelterbelts were not sustainable. Agronomic land surveys of the facilities confirmed the poor soil quality would not sustain the tree shelterbelts. As a result, the District eliminated this option as a BACT requirement for these specific CAFs and allowed an alternative mitigation measure to be implemented.

For the reasons listed above, it is infeasible to require planting tree shelterbelts at animal facilities; however, the trees and plants in the agricultural fields and orchards that surround Valley animal facilities already capture a portion of emissions from these facilities and remove some of the ammonia by deposition. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Using Plants with Improved Nitrogen Use Efficiency** - ***(applies to all cattle)***

This measure involves developing new plant varieties with improved genetic traits for the capture of soil nitrogen, which would allow reduced fertilizer application. New plant varieties could also be developed with improved nutritional characteristics. This measure is theoretical and requires extensive research and funding to develop new plant varieties with the desired traits. Years of testing would be required to evaluate the effectiveness of new plant varieties for reducing ammonia emissions and any adverse impacts of the new plant varieties. Furthermore, capturing additional soil nitrogen would primarily benefit water quality rather than reducing ammonia emissions. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Changing Land Use from Arable to Woodland** - ***(applies to all CAFs)***

This measure involves changing land use from agricultural land to permanent woodland. However, many areas in the Valley are dry and often affected by droughts, and thus not suitable for the establishment of permanent woodlands. The District does not have authority to require that agricultural land be converted to forests. Moreover, conversion of agricultural land to farmland would result in total loss of income for the farmers and an associated loss in tax revenue. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

**Reduced consumption of meat and eggs by humans by 63 percent** - ***(applies to all CAFs)***

The District does not have authority to regulate what people eat and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

## Evaluation of Potential Emissions Reductions from CAFs

As demonstrated in the evaluation above, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through Rule 4570. These measures are reducing CP content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. This was calculated as follows.

- Control efficiency of reducing CP content in feed for beef finishing cattle, applied to beef cattle emissions inventory:

  18.9% x 16.2 tpd = 3.1 tpd

- Control efficiency of incorporation of solid manure within 24 hours, applied to beef and dairy cattle emissions inventory:

  0.48% x 141.5 tpd = 0.7 tpd

- Control efficiency of acidifying amendments for poultry litter and manure, applied to broiler and layer emissions inventory:

  35% x 7.9 tpd = 2.8 tpd

The emissions reductions from the measures above total 6.6 tpd, which would be reduced from the total ammonia emissions inventory of 324.9 tpd:

6.6 tpd ÷ 324.9 tpd = 2.0%

Overall, ammonia emissions from CAFs in the Valley can only be reduced by 2 percent by implementing the mitigation measures above. This demonstrates that additional reductions in the EPA-recommended range of 30-70 percent are infeasible.

## Fertilizers

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the Farmland Mapping & Monitoring Program (FMMP) of the California Department of Conservation.

The California Department of Food and Agriculture (CDFA) Feed, Fertilizer and Livestock Drugs Regulatory Services (FFLDRS) Branch primary focus is to ensure in every way possible a clean and wholesome supply of meat and milk, and to promote environmentally safe and agronomically sound use and handling of fertilizer materials. This is performed through regulating manufacturing, labeling, and use of fertilizing materials, feed and livestock drugs.

The CDFA Fertilizer Research and Education Program (FREP) funds and facilitates research to advance the environmentally safe and agronomically sound use and handling of fertilizing materials. FREP is voluntary and serves growers, agricultural supply and service professionals, extension personnel, public agencies, consultants, and other interested parties.

The Fertilizer Inspection Advisory Board (FIAB) is a statutory body that is advisory to the CDFA secretary on matters pertaining to fertilizer issues, including FREP activities. The Board consists of nine persons appointed by the secretary of agriculture, one of whom shall be a public member and eight of whom shall be licensed with CDFA to manufacture or distribute fertilizing materials, including organic inputs. The FIAB established the Technical Advisory Subcommittee (TASC) to advise the FIAB on matters related to the funding of FREP projects. The TASC serves as an expert scientific panel on matters concerning plant nutrition and on environmental effects related to fertilizing materials use. TASC assists in setting research priorities, reviews research proposals, and makes recommendations on projects for funding.

The composition of the TASC is determined by the FIAB. There should be at least nine members representing the major segments of the fertilizer industry, certified crop advisors, technical experts, farming community, public, and governmental agencies. Members have to demonstrate knowledge, technical and scientific expertise in the fields of fertilizing materials, agronomy, plant physiology, principles of experimental research, production agriculture, and environmental issues related to fertilizing materials use. One member can satisfy more than one of the criteria stated above. At minimum, one member shall be appointed from the membership of the FIAB, and one member on the TASC shall be from CDFA.

The TASC meets at least two times per year-once in spring to evaluate concept proposals and once in summer to evaluate full proposals. Additional meetings are necessary for special initiatives. Meetings typically last all day and alternate between Sacramento and other locations throughout the State. Serving on the TASC requires a time commitment in addition to participating in meetings. Members must read and critically evaluate all concept proposals (typically around 35 two-page proposals) and full proposals (typically at least ten 15-page proposals). In addition, TASC members are responsible for reviewing final research reports for FREP funded projects and may be asked to participate in conferences and special initiatives.

CARB has not found an ammonia emission reduction measure for fertilizers that meets EPA requirements for SIP submittal. CARB staff reached out to the National Association of Clean Air Agencies (NACAA) to ascertain whether other air pollution control agencies across the United States had any experience or regulations reducing ammonia emissions from fertilizers. NACAA reached out to all of their members and CARB staff did not receive any existing rules or regulations controlling ammonia emissions from fertilizers. CARB staff also reached out to

EPA Region 9 staff whether they were aware of any rules or regulations controlling ammonia emissions from fertilizers and they were not aware of any. EPA Region 9 staff did ask CARB to review some practices per Table 12.

**Mitigation Measures**

**Table 13: Fertilizer Mitigation Measures Evaluated**

| Method | Measure | Reference |
|---|---|---|
| Fertilizer | Optimizing or minimizing use of fertilizer | Guthrie |
| | Adding a Urease Inhibitor | Guthrie |
| | Mixing and injecting fertilizer into the soil quickly | Guthrie and Eory |
| | Applying fertilizer during optimal weather conditions | Guthrie and Eory |

**Optimize or minimize use of fertilizer**

The San Joaquin Valley is a part of Central Valley Water Board of the California Water Board, which is an expansive region extending south from the Oregon border to the northernmost portion of Los Angeles County. The California Legislature passed Senate Bill 390 in 1999, which required Water Boards to develop programs that regulate agricultural lands in accordance with the Porter-Cologne Water Quality Control Act (California Water Code Division 7). In 2003, the Central Valley Irrigated Lands Regulatory Program (ILRP) was established, regulating agricultural discharges to surface waters. The Central Valley Water Board extended the regulations in 2012 to include discharges to ground waters. With the exclusion of lands that are never-irrigated or are covered under a separate Central Valley Water Board program, all commercial irrigated lands are required to obtain regulatory coverage under the ILRP.[199] In accordance with the ILRP, growers are required to prepare farm management plans – which includes an Irrigation Nitrogen Management Plan Summary Report – that comply with the approved upon Waste Discharge Requirements (WDR). Using information from the Reports, inferences can be made about nitrogen management based on estimates that compare nitrogen applied (A) to the nitrogen removed (R) from a field: A/R ratio and A-R difference. Included in the nitrogen fraction is any nitrogen proactively added

[199] Central Valley Water Board. *Irrigated Lands Regulatory Program (ILRP) FAQs*. Available at: *https://www.waterboards.ca.gov/centralvalley/water_issues/irrigated_lands/ilrp_faq.pdf*

to a field such as organic amendments, synthetic fertilizers, manure, and irrigation water, whereas nitrogen removed refers to the nitrogen in the materials removed from the field.[200]

Though growers do not have an immediate requirement under ILRP to use nitrogen efficient strategies, growers that are deemed outliers in A/R ratio and A-R difference would be required to employ enhanced strategies to lower these estimates. CDFA FREP offers an Irrigation and Nitrogen Management training program[201] for this purpose among others. A subset of the Irrigation and Nitrogen Management training program is dedicated to nitrogen efficiency, including overviews of the "4 R's" of nitrogen management, and of efficient nitrogen practices.[202] The 4 R's principles are founded on applying the "Right source" of nitrogen at the "Right rate", "Right time", and "Right place". The right rate principle is with the identified measure, as it promotes strategies for providing nitrogen in rates that do not go beyond the crop demand for nitrogen. Examples of how this can be accomplished include adjusting the rate of application based on expected crop yield and adjusting season application rates based on soil and plant-tissue testing.

Guthrie et al. (2018) describe how minimizing the amount of fertilizer applied to an level that is optimal for crop can reduce ammonia emissions.[203] This measure and associated findings were not well described by both Guthrie et al. (2018) and the publications they referenced, nor were any specific regulations identified.[204,205,206,207] Additionally, the viewpoints of Guthrie et al. (2018) were prepared in the context of Europe and United Kingdom. There is therefore

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[200] California State Water Resources Control Board. *State of California State Water Resources Control Board, Order WQ 2018-0002.* Available at: *https://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2018/wqo2018_0002_with_data_fig1_2_appendix_a.pdf*

[201] CDFA. *Fertilizer Research and Education Program*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/*

[202] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[203] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[204] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

[205] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[206] Collins, A.L., Y.S. Zhang, M. Winter, A. Inman, J.I. Jones, P.J. Johnes, W. Cleasby, E. Vrain, A. Lovett, L. Noble. (2016). Tackling agricultural diffuse pollution: What might uptake of farmer-preferred measures deliver for emissions to water and air? Science of The Total Environment 547, 269-281. *https://doi.org/10.1016/j.scitotenv.2015.12.130*

[207] Dalgaard, T., J. F. Bienkowski, A. Bleeker, U. Dragosits, J. L. Drouet, P. Durand, A. Frumau, N. J. Hutchings, A. Kedziora, V. Magliulo, J. E. Olesen, M. R. Theobald, O. Maury, N. Akkal, P. Cellier. (2012). Farm nitrogen balances in six European landscapes as an indicator for nitrogen losses and basis for improved management. Biogeosciences 9, 5303–5321. *https://doi.org/10.5194/bg-9-5303-2012*

a probability that the conditions and farming practices described by Guthrie et al. (2018) are consistent with those present and employed in California. This, combined with the lack in strong evidence demonstrating the emission reduction potentials, demonstrates the need for additional research be completed under conditions consistent with those of the San Joaquin valley before this measure can be considered.

**Urease Inhibitor**

When combined with urease enzyme present in plants, urea present in urea-based fertilizers can be converted into ammonia, which can then volatilize. Urease inhibitors are a class of nitrogen stabilizer designed to minimize volatilization from applied nitrogen sources by inhibiting the action of the urease, thereby reducing the formation of ammonia.

Nitrogen stabilizers are regulated by federal and State regulatory agencies. At the federal level, The Federal Insecticide, Fungicide, and Rodenticide Act requires that nitrogen stabilizers sold and distributed in the United States be registered with U.S. EPA.[208] At the state level, both the California Department of Pesticide Regulations (DPR) and CDFA maintain regulatory authorities over nitrogen stabilizers. While DPR requires all nitrogen stabilizers to be registered,[209] CDFA regulates licensing, registration, labeling, tonnage reporting, and inspection of only a subset of commercial nitrogen stabilizers.[210] In coordination with 4R Nutrient Stewardship and UC Davis Land and Water Resources, CDFA FREP also encourage growers to use enhanced-efficiency sources such as Urease Inhibitors, identifying these sources as possible "Right Source" through their 4 R's principles.[211]

Although urease inhibitors have shown tremendous promise in reducing ammonia emissions, some studies indicate potential occurrences of pollution swapping through increasing of NOx emissions which must be critically considered and explored prior to further considering the measure.[212,213] Additionally, although there are numerous identified benefits associated with the use urease inhibitors, there is little existing knowledge about their potential to enter the

[208] US EPA. *Nitrogen Stabilizer Products that Must Be Registered under FIFRA*. Available at: *https://www.epa.gov/pesticide-registration/nitrogen-stabilizer-products-must-be-registered-under-fifra*

[209] CDPR. *A Guide to Pesticide Regulation in California 2017 Update*. Available at: *https://www.cdpr.ca.gov/docs/pressrls/dprguide/dprguide.pdf*

[210] CDFA. *California Fertilizer Laws and Regulations*. Available at: *https://www.cdfa.ca.gov/is/docs/Fertilizer_Law_and_Regs.pdf*

[211] CDFA FREP. *California Crop Fertilization Guidelines.* Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/FertilizationGuidelines/Adjustments.html#h11*

[212] Drury, C.F., X. Yang, W.D. Reynolds, W. Calder, T.O. Oloya, A.L. Woodley. (2017). Combining Urease and Nitrification Inhibitors with Incorporation Reduces Ammonia and Nitrous Oxide Emissions and Increases Corn Yields. Journal of Environmental Quality 46:5, 939-949. *https://doi.org/10.2134/jeq2017.03.0106*

[213] Mirkhani, R., C. Resch, G. Weltin, L. K. Heng, J. Mitchell, R. Clare Hood-Nowotny, G. Dercon. (2023). Effect of urease inhibitor and biofertilizer on nitrous oxide emission, EGU General Assembly 2023, Vienna, Austria, 24–28 Apr 2023, EGU23-11242, *https://doi.org/10.5194/egusphere-egu23-11242*

food chain and impact food safety.[214] Further research is needed which demonstrates that there are no food safety-related issues prior to this measure being viable for consideration.

According to Guthrie et al. (2018), the addition of a urease inhibitor has the potential to reduce ammonia emissions by 40-70 percent.[215] Though this has the potential to hold remarkable mitigation potential, their estimates along with those of the original experiments, were prepared under European and United Kingdom conditions. As these findings were based outside of California where environmental and climatic conditions may differ, further research is needed that explores the reduction potentials of urease inhibitors in conditions consistent with those of the San Joaquin Valley. In addition to this, Guthrie et al. (2018) merely identified the measures but did not reference or identify any specific regulations.

**Quick mixing and injecting into soil**

The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. As previously described, with the implementation of ILRP and WDRs by the Central Valley Water Board growers are required to prepare and management plans. The 4 R's of nitrogen management serve as guiding nitrogen efficiencies principles that growers are recommended to follow when developing their management plans. The identified measure is addressed through two of the four principles. The "Right time" principle refers to timed application of nitrogen to ensure availability to the plant during periods of greatest demand. The measure is also addressed through the "Right place" principle, which considers targeted application of fertilizer in the crop's effective rootzones to facilitate and enhance the uptake of nitrogen by the crop.

As described by Guthrie et al. (2018), ammonia emissions can be reduced by 50-90 percent through this measure, should the fertilizer be mixed in or injected into the soil within 4-6 hours of their application.[216] Though they do not touch on the speed of the process, Eory et al. (2016) likewise identified fertilizer injection as a candidate ammonia emission mitigation measure.[217] However, the publications referenced in Guthrie et al. (2018) and Eory et al. (2016) focus solely on manure application methods and do not provide estimates for

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[214] Byrne M.P., J.T. Tobin, P.J. Forrestal, M. Danaher, C.G. Nkwonta, K. Richards, E. Cummins, S.A. Hogan, T.F. O'Callaghan. (2020). Urease and Nitrification Inhibitors—As Mitigation Tools for Greenhouse Gas Emissions in Sustainable Dairy Systems: A Review. Sustainability 12:15, 6018. *https://doi.org/10.3390/su12156018*

[215] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[216] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[217] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

commercial fertilizers. [218,219] We cannot assume the mitigation potential of fertilizers to be consistent with that of manure sources. We therefore proceed with caution with the identified measure and will not be considering it at this moment. In addition to this, research from a California-context is profoundly limited,[220] resulting in uncertainty regarding the ammonia reduction potentials under California-specific conditions. Consistent with the previously mentioned fertilizer measures, Guthrie et al. (2018) and Eory et al. (2016) merely identify the measure, and do not reference any specific regulations.

**Application during optimal weather conditions**

Weather conditions (i.e., air temperature, precipitation, and wind speed) have a demonstrated effect on ammonia fluxes.[221] The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. The 4 R's "Right time" principle covers the issue that this measure aims to address. The principle is based on timed nitrogen application in order to ensure the availability of nitrogen to the plant during the more nutrient demanding periods. This period is during vegetative growth in annual crops, and during early fruit and nut development in mature trees and vines.[222]

While describing the fertilizer injection measure, Eory et al. (2016) convey that additional work is needed to determine the emission benefits related to fertilizer application with respect to weather.[223] They however do not provide any additional or specific information regarding a measure or identify the reduction potential of its application. Guthrie et al. (2018) identified weather as affecting ammonia emissions by up to 5 percent and provided the recommendation that growers refrain from using urea-based fertilizers during warm, dry, and

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[218] Loyon, L., C.H. Burton, T. Misselbrook, J. Webb, F.X. Philippe, M. Aguilar, M. Doreau, M. Hassouna, T. Veldkamp, J.Y. Dourmad, A. Bonmati, E. Grimm, S.G. Sommer. (2016). Best available technology for European livestock farms: Availability, effectiveness and uptake. Journal of Environmental Management 166, 1-11. *https://doi.org/10.1016/j.jenvman.2015.09.046*

[219] Webb, J., B. Pain, S. Bittman, J. Morgan. (2010). he impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—A review. Agriculture, Ecosystems & Environment 137:1-2, 39-46. *https://doi.org/10.1016/j.agee.2010.01.001*

[220] Krauter, C., D. Goorahoo, C. Potter, S. Klooster. (2014). *Ammonia Emissions and Fertilizer Applications in California's Central Valley*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/completedprojects/00-0515Krauter2006.pdf*

[221] Li, Q., X. Cui, X. Liu, M. Roelcke, G. Pasda, W. Zerulla, A.H. Wissemeier, X. Chen, K. Goulding, F. Zhang. (2017). A new urease-inhibiting formulation decreases ammonia volatilization and improves maize nitrogen utilization in North China Plain. Scientific Reports 7, 43853. https://doi.org/10.1038/srep43853, *https://doi.org/10.1038/srep43853*

[222] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[223] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

windy conditions.[224] After reviewing the two publications referenced in Guthrie et al. (2018) for this measure, Zhang et al. (2017)[225] and Newell et al. (2011)[226], no information regarding concerning weather-related conditions was found. Other publications have demonstrated a link between weather conditions and ammonia emissions, though it is unclear which environmental factors are most appropriate for the various fertilizer types.[227,228] It is particularly important for further research to address the impact of weather and fertilizer application timing under conditions specific to the San Joaquin Valley. Lastly, as has been described previously, Guthrie et al. (2018) and Eory et al. (2016) do not refer to any specific regulations when identifying the measure.

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the

CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers, the second largest category of emissions in the Valley. CARB's main source of authority is the California Health and Safety Code. CARB's authority is primarily over mobile sources, consumer products, and air toxics, as well as methane from livestock (see Cal. Health & Saf. Code §§ 43013, 39666, 39730.7, 41712).

Estimated feasible reductions in ammonia from this emissions source in the Valley are zero tons.

## Composting and Other Sources

The District already regulates ammonia emissions from composting operations through District Rules 4565 and 4566. Based on the mitigation measures in practice at facilities

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[224] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[225] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[226] Newell Price, J.P., D. Harris, M. Taylor, J.R. Williams, S.G. Anthony, D. Duethmann, R.D. Gooday, E.I. Lord, B.J. Chambers, D.R. Chadwick, T.H. Misselbrook. "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[227] V Venterea, R.T., A.D. Halvorson, N. Kitchen, M.A. Liebig, M.A. Cavigelli, S.J. Del Grosso, P.P. Motavalli, K.A. Nelson, K.A. Spokas, B. Pal Singh, C.E. Stewart, A. Ranaivoson, J. Strock, H. Collins. (2012). Challenges and opportunities for mitigating nitrous oxide emissions from fertilized cropping systems. Frontiers in Ecology and the Environment 10:10, 562-570. *https://doi.org/10.1890/120062*

[228] Grahmann, K., N. Verhulst, A. Buerkert, I. Ortiz-Monasterio, B. Govaerts. (2013). Nitrogen use efficiency and optimization of nitrogen fertilization in conservation agriculture. Cabi Reviews 8:053. *https://doi.org/10.1079/PAVSNNR20138053*

subject to Rule 4565 and 4566, ammonia emissions are already being reduced by 44 percent. With these controls in place, composting accounts for only 2 percent of the District's ammonia emissions; therefore, the District will not be further evaluating this source category at this time.

The other source category consists of ammonia emissions primarily from mobile sources and fuel combustion, which are heavily controlled. Therefore, the District will not be further evaluating this source at this time.

Estimated feasible reductions in ammonia from these emissions sources in the Valley are zero tons.

## 4. Research

CARB is working to fill knowledge gaps on feasible and effective ammonia controls. Development of effective air pollution mitigation strategies for ammonia requires additional spatiotemporal understanding of atmospheric ammonia emissions that are currently lacking as a result of limited data. CARB is conducting research, both in-house and with external partners, to characterize gaseous ammonia emissions from agricultural activities in the San Joaquin Valley. The results of these studies will help future development of CARB's ammonia emission inventory, SIP, Short-Lived Climate Pollutant Reduction Strategy, and community air protection program (AB 617). Findings from these research projects will help CARB better characterize ammonia emissions in the Valley, as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

Ammonia emissions in general are not well quantified Statewide and further focused study is needed to facilitate quantification and potential further control strategies that are effective and cost-effective. As an example of the agency's work in this area, CARB's Research Division has developed a new mobile measurement platform equipped with a state-of-the-science ammonia analyzer and other advanced analytical instruments to improve the understanding of various ammonia sources in California. In September and October 2018, CARB staff collaborated with researchers from the University of California, Davis, to quantify emissions from several dairies in the Valley as part of the ongoing projects funded by the California Department of Food and Agriculture, CARB, and industry. Methane, oxides of nitrogen, and other air pollutants and meteorological parameters were measured at or near dairies in addition to ammonia. The major objective is to evaluate the effectiveness of various alternative manure management practices (AMMP) with respect to emission reductions as CARB staff will revisit these dairies after they implement the selected AMMP technologies. This effort is a direct response to Senate Bill 1383 requirements and goals. The AMMP is designed to identify air pollution sources and estimate their emission rates. Its mobility makes it ideal for field measurements that require large spatial coverage, such as mapping ammonia mixing ratios with an emphasis on determining the magnitude of emissions, characterizing spatial variability of emissions, and identifying dominant sources of emissions.

In addition, CARB is undertaking a suite of projects that address research needs. Many projects focus on emissions from dairies, while others, including those with a satellite or remote sensing component, can offer insight into ammonia emissions in the Valley from all source categories. CARB staff is also working with academic researchers and industry representatives to explore potential opportunities to reduce the emissions of ammonia and other air pollutants from dairy manure lagoons which are one of the largest contributors to ammonia in California. Preliminary experiments have been conducted, and further investigation is underway at some Valley dairies with the support from farmers. Additionally, CARB staff is planning to analyze existing satellite data to refine the spatial resolution and allocation of ammonia in California. This may also help evaluate the impact of major wildfires on surface ammonia levels in recent years, and can be used to compare with the estimation methodology in the current ammonia emission inventory associated with wildfires.

Due to research which indicates California is underestimating ammonia emissions in the air, CARB is reviewing and will reassess ammonia estimates in recognition of this research. This effort will help us update our understanding about modeled sensitivity of PM2.5 formation to changes in ammonia emissions.

## 5. Conclusion

While EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, CARB and the District have determined that the 30 percent reduction in ammonia emissions is not achievable Moreover, CARB and the District have not identified methods within its authority to control air emissions of ammonia that achieve an overall 30 percent reduction in ammonia emissions. In practice, the District has implemented the best available control measures on livestock operations that have already achieved approximately 25 percent reduction from this source. CARB is not aware of controls that would achieve greater reductions on the order needed to achieve an overall 30 percent reduction of ammonia emissions in the Valley; nevertheless, CARB is pursuing further research specific to California and the Valley to improve our understanding of ammonia emissions from various sources as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

The District and CARB analyzed potential control measures to reduce ammonia emissions from key source categories in order to evaluate whether a 30 percent reduction in emissions is feasible. Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions. EPA provided the list of measures to CARB and the District and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. Overall, ammonia emissions in the Valley can only be reduced from the confined animal facilities source category by 2 percent by implementing these mitigation measures. For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules for the source. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources.

Based on the extensive evaluation which identified feasible reductions of only approximately 2 percent, as summarized below in Table 14, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

**Table 14. Estimated Feasible Emission Reductions**

| Emissions Category | Emissions (tpd, 2023) | Identified Controls | Feasible Ammonia Reductions |
|---|---|---|---|
| Confined Animal Feeding | 186.5 | • Reducing crude protein content in feed for beef finishing cattle<br>• Incorporation of solid manure within 24 hours<br>• Acidifying amendments for poultry litter and manure | 6.6 tpd |
| Fertilizers | 111.2 | No authority or feasible controls identified | 0 |
| Composting | 6.7 | No feasible controls identified | 0 |
| Other sources | 20.5 | No feasible controls identified | 0 |
| Total Ammonia | 324.9 | | 6.6 tpd |

A 2 percent reduction is consistent with the national trend identified in EPA guidance which stated that ammonia changes ranged nationally from an increase of six percent to a decrease of nine percent.[229] Moving forward, updated national guidance on ammonia emission reductions achievable in practice is needed, as well as guidance on available and feasible control measures.

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. Considering relevant contextualizing information including available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia from control requirements in the SIP.

[229] EPA. *PM2.5 Precursor Demonstration Guidance*. May 2019. *https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf*

# ATTACHMENT T

# APPENDIX E

**California Environmental Quality Act**

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**Functional Equivalent Document**

# Renewable Electricity Standard


**Prepared by:**

**California Air Resources Board**

**Prepared by:**

**Ascent Environmental, Inc.**
455 Capitol Mall, Suite 210
Sacramento, CA 95814


**June 2010**

# Functional Equivalent Document

# Renewable Electricity Standard

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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| AADT | average annual daily traffic |
| AB | Assembly Bill |
| ACEC | Area of Critical Environmental Concern |
| ACHP | Advisory Council on Historic Preservation |
| AICUZ | Department of Defense Air Installations Compatible Use Zones |
| ALUC | Airport Land Use Commission |
| amsl | above mean sea level |
| APE | area of potential effect |
| APEFZ | Alquist-Priolo Earthquake Fault Zone |
| ARB | California Air Resources Board |
| BAAQMD | Bay Area Air Quality Management District |
| BACT | best available control technology |
| BLM | U.S. Bureau of Land Management |
| BMPs | best management practices |
| bmsl | below mean sea level |
| BOR | U.S. Bureau of Reclamation |
| CAA | Clean Air Act |
| CAL FIRE | California, Department of Forestry and Fire Protection |
| Cal ISO | California Independent System Operator |
| CAL Recycle | State of California, Department of Resources Recycling and Recovery |
| Cal/EPA | California Environmental Protection Agency |
| Caltrans | California Department of Transportation |
| CBC | California Building Code |
| CCCT | closed circuit cooling tower |
| CCNM | California Coastal National Monument |
| CCP | comprehensive conservation plans |
| CCR | California Code of Regulations |
| CDCA | California Desert Conservation Area |
| CDPA | California Desert Protection Act |
| CEC | California Energy Commission |

| | |
|---|---|
| CEQA | California Environmental Quality Act |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| CFCP | California Farmland Conservancy Program |
| CFR | Code of Federal Regulations |
| CGS | California Geological Survey |
| CHP | combined heat and power |
| CI | Circulation and Infrastructure |
| CNEL | Community Noise Equivalent Level |
| CNRA | California Natural Resources Agency |
| CO | Conservation |
| CPUC | California Public Utilities Commission |
| CREZ | competitive renewable energy zones |
| CRHR | California Register of Historical Resources |
| CT | simple cycle cooling tower |
| CUPA | Certified Unified Program Agency |
| CVMSHCP/NCCP | Coachella Valley Multi-Species Habitat Conservation Plan/Natural Communities Conservation Plan |
| CVP | Central Valley Project |
| CWA | Clean Water Act |
| dB | decibel |
| dBA | A-weighted sound levels |
| Delta | Sacramento-San Joaquin Delta |
| DFG | Department of Fish and Game |
| DOGGR | California Division of Oil, Gas, and Geothermal Resources |
| DPR | Department of Parks and Recreation |
| DTSC | Department of Toxic Substances Control |
| DWR | California Department of Water Resources |
| E3 | Energy and Environmental Economics, Incorporated |
| EDCs | endocrine disrupting compounds |
| EIRs | Environmental Impact Reports |
| EIS | environmental impact statement |
| EPA | U.S. Environmental Protection Agency |

| | |
|---|---|
| EPCRA | Environmental Planning and Community Right-to-Know Act |
| FAA | Federal Aviation Administration |
| FED | functionally equivalent document |
| FEMA | Federal Emergency Management Agency |
| FHA | Federal Highway Administration |
| FHWA | Federal Highway Administration |
| FLPMA | Federal Land Policy and Management Act |
| FMMP | Farmland Mapping and Monitoring Program |
| FPPA | Farmland Protection Policy Act |
| FRA | Federal Rail Administration |
| FTA | Federal Transit Administration |
| g | gravity |
| GC | Government Code |
| GHG | greenhouse gases |
| H | Housing |
| HCP | habitat conservation plan |
| HLRs | Hydrologic landscape regions |
| IEPR | Integrated Energy Policy Report |
| in/sec | inches per second |
| IOUs | investor owned utilities |
| ISEGS | Ivanpagh Solar Electric Generating Systems |
| kW | kilowatts |
| lb/MWh | pound per megawatt hour |
| $L_{dn}$ | Day-Night Noise Level |
| LEA | local enforcement agencies |
| $L_{eq}$ | Equivalent Noise Level |
| $L_{max}$ | Maximum Noise Level |
| $L_{min}$ | Minimum Noise Level |
| LOS | level of service |
| LU | Land Use |
| mg/L | milligrams per liter |
| Moyer program | ARB's Carl Moyer Program |
| MPOs | metropolitan planning organizations |

| | |
|---|---|
| MPS | modular pumped storage |
| MRDS | USGS Mineral Resource Data System |
| MRZ | Mineral Resource Zones |
| MUC | Multiple-Use Class |
| MW | megawatts |
| MWh | megawatt-hour |
| mya | million years ago |
| NAAQS | National Ambient Air Quality Standards |
| NAGPRA | Native American Graves Protection and Repatriation Act of 1990 |
| NCAs | National Conservation Areas |
| NCCP | natural communities conservation plan |
| NCP | National Contingency Plan |
| NCPA | Northern California Power Agency |
| NECO | Northern and Eastern Colorado Desert |
| NEPA | National Environmental Policy Act [ |
| NFMA | National Forest Management Act |
| NFS | National Forest System |
| NHPA | National Historic Preservation Act |
| NLCS | National Landscape Conservation System |
| NPDES | National Pollution Discharge Elimination System |
| NPL | National Priority List |
| NPS | National Park Service |
| NRHP | National Register of Historic Places |
| NRPA | Archaeological Resources Protection Act of 1979 |
| $O_2$ | oxygen |
| O&M | operation and maintenance |
| OAQPS | Office of Air Quality Planning and Standards |
| OHMVR | off-highway motor vehicle recreation |
| OS | Open Space |
| OTC | once through cooling |
| OWTS | onsite wastewater treatment systems |
| oxide | aluminum |
| PA | Programmatic Agreements |

| | |
|---|---|
| PCBs | polychlorinated biphenyls |
| PEIS | Programmatic Environmental Impact Statement |
| PM | Particulate matter |
| POUs | publicly owned utilities |
| ppmv | parts per million by volume |
| PPV | peak particle velocity |
| PRC | Public Resources Code |
| PV | Photovoltaic |
| RCRA | Resource Conservation and Recovery Act |
| REC | renewable energy credit |
| RES | Renewable Electricity Standard |
| RETI | Renewable Energy Transmission Initiative |
| RMPs | Resource Management Plans |
| RMS | root-mean-square |
| ROWD | Report of Waste Discharge |
| ROWs | right-of-ways |
| RPS | Renewables Portfolio Standard |
| RWQCB | Regional Water Quality Control Board |
| SARA | Superfund Amendments and Reauthorization Act |
| SBE | State Board of Education |
| SCAQMD | South Coast Air Quality Management District |
| Scoping Plan | AB 32 Climate Change Scoping Plan |
| SCPPA | Southern California Public Power Authority |
| SCS | Sustainable Communities Strategy” |
| SDAPCD | San Diego Air Pollution Control District |
| SDWA | Safe Drinking Water Act |
| SERCs/TERCs | state/tribe emergency response commissions |
| SIC | Standard Industrial Classification |
| SIP | State Implementation Policy |
| SJVAPCD | San Joaquin Valley Air Pollution Control District |
| SMARA | California Surface Mining and Reclamation Act |
| SMUD | Sacramento Municipal Utility District |
| solar DG | distributed solar generation |

| | |
|---|---|
| SVRA | State Vehicular Recreation Area |
| SWAMP | Surface Water Ambient Monitoring Program |
| SWP | State Water Project |
| SWPPP | Storm Water Pollution Prevention Plan |
| SWRCB | State Water Resources Control Board |
| TAC | toxic air contaminant |
| TDS | Total dissolved solids |
| TMDL | Total Maximum Daily Load |
| tpy | tons per year |
| TRI | Toxics Release Inventory |
| TSCA | Toxic Substances Control Act |
| U.S. EPA | U.S. Environmental Protection Agency |
| UBC | Uniform Building Code |
| USACE | U.S. Army Corps of Engineers |
| USBR | U.S. Bureau of Reclamation |
| USFS | U.S. Forest Service |
| USFWS | U.S. Fish and Wildlife Service |
| UXO | unexploded ordnance |
| V/C | volume-to-capacity ratio |
| VC | Vehicle Code |
| VdB | vibration decibels |
| VOCs | volatile organic compounds |
| VRI | Visual Resource Inventory |
| VRM | Visual Resource Management |
| WAPA | the Western Area Power Administration |
| WDRs | waste discharge requirements |
| WECC | Western Electricity Coordinating Council |
| WECO | Western Colorado |
| WEMO | West Mojave Habitat Conservation Plan |
| WSA | water supply assessment |

# I. INTRODUCTION AND BACKGROUND

## A. INTRODUCTION

The California Environmental Quality Act (CEQA) and California Air Resources Board (ARB) policy require an analysis to determine any potentially significant adverse environmental impacts of ARB's regulations. The Renewable Electricity Standard (RES) is proposed to be adopted as a regulation. If adopted, it would advance the standard for the proportion of electricity generation by eligible renewable sources from 20 percent, as established in 2002 by the California Renewables Portfolio Standard (RPS), to 33 percent. The proposed 33 percent RES would modify other provisions contained in the existing RPS, as described in Chapter II.

RES is identified as one of the measures proposed in the Climate Change Scoping Plan (Scoping Plan), which was developed for the purpose of reducing emissions of greenhouse gases (GHG) in California, as directed by the California Global Warming Solutions Act of 2006 (AB 32, Chapter 488, Statutes of 2006). One of the key elements of the Scoping Plan recommendations is "Achieving a statewide renewables energy mix of 33 percent." As described in the Scoping Plan recommendations, "increasing the 20 percent RPS to 33 percent is designed to accelerate the transformation of the electricity sector, including investment in the transmission infrastructure and system changes to allow integration of large quantities of intermittent wind and solar generation," and other eligible renewable sources.

## B. THE CALIFORNIA ENVIRONMENTAL QUALITY ACT AND FUNCTIONAL EQUIVALENCY

In PRC Section 21080(a) CEQA states, "Except as otherwise provided in this division, this division shall apply to discretionary projects proposed to be carried out or approved by public agencies, including but not limited to the enactment and amendment of zoning ordinances, the issuance of zoning variances, the issuance of conditional use permits, and the approval of tentative subdivision maps, unless the project is exempt from this division. " ARB determined that adoption and implementation of the proposed 33 percent RES constitutes a "project" as defined by Public Resources Code Section 21000 et seq. The CEQA Guidelines, Section 15378, define a project as:

(a) "Project" means the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is any of the following:

   (1) An activity directly undertaken by any public agency including but not limited to public works construction and related activities clearing or grading of land, improvements to existing public structures, enactment and amendment of zoning ordinances, and the adoption and amendment of

viewsheds of State Routes 14 and 58. For wind farms that would be sited along ridgelines and open plains, the wind turbines would be more prominent and would further increase the contrast between the natural and artificial visual environment, potentially damaging the visual character of the area. Views of construction and operation activities may be visible to some viewer groups in the area, including motorists along State Routes 14 and 58, residents in nearby communities, and recreationists using the Pacific Crest Trail. Residents and recreationists would be expected to experience a longer duration of views as opposed to motorists who would be passing through the Tehachapi area at higher speeds. However, the visual impact of wind turbines and associated facilities depends on several variables, including viewing distance, angle of view, and structure placement in the landscape. Because the Tehachapi Wind Resource Area already includes wind farms, it is possible that wind energy development in this area would not substantially exacerbate scenic impacts of State Routes 14 and 58. However, because specific locations are unknown, it is possible that wind turbines could be constructed in more pristine areas, resulting in significant scenic impacts.

#### *Out of State – Low and High Load Conditions*

Under the 20 percent low and high load conditions, implementation of the same degree of wind energy resource projects in Montana, the Pacific Northwest, Utah, Southern Idaho, and Wyoming may result in significant adverse effects on scenic vistas, scenic resources, and visual character in these areas. Some of these projects may occur on federal lands, which would subject such projects to environmental review of aesthetic impacts under NEPA. In some cases, renewable energy resource projects may also occur in states where such projects would be subject to the state's environmental review process. In any case, however, implementation of renewable energy resource projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land and would result in substantial alteration of the visual landscape. Implementation of Mitigation A-1 through A-10 would reduce scenic impacts, but it is uncertain whether mitigation would be sufficient to reduce the impact to a less than significant level.

Scenic impacts of wind energy development under the 20 percent RPS low and high load conditions would be potentially significant. This impact would be expected to occur even without adoption of the RES.

### *33 Percent Renewable Electricity Standard*

#### *Distributed Statewide – Low and High Load Conditions*

No additional distributed wind energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

#### *Tehachapi – Low and High Load Conditions*

Under the 33 percent RES, wind energy and transmission development in the Tehachapi area would be the same under both low and high load conditions, and the same as the high load condition under the 20 percent RPS. As such, scenic impacts of some locations, the visible changes to these scenic resources may be potentially significant.

***Out of State – Low and High Load Conditions***
Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar thermal would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar thermal and transmission line development under the 33 percent RES low and high load conditions would be significant.

## Solar Photovoltaic

## *20 Percent Renewable Portfolio Standard*

***Distributed Statewide – Low and High Load Conditions***
Development of solar photovoltaic energy would occur in various locations throughout the State under the 20 percent RPS low and high conditions. Construction and operation of solar photovoltaic panels, access roads, and associated facilities would introduce new elements that have the potential to substantially degrade the existing quality of sites, particularly those in undeveloped areas. While specific locations of distributed solar photovoltaic energy development are unknown, such development may occur in areas with national, state, or county designated scenic vistas, other scenic resources, and State scenic highways. Solar photovoltaic development has the potential to substantially damage scenic resources.

***Tehachapi – Low and High Load Conditions***
Under the 20 percent RPS solar photovoltaic energy and transmission development is expected to occur in the Tehachapi area under both low and high load conditions. High load conditions under the RPS would require approximately three times the solar photovoltaic generation from this area. Although there are no officially designated State scenic highways in the Tehachapi area, portions of State Routes 14 and 58, which intersect near the Tehachapi Mountains, are eligible for designation. Depending on the locations of solar photovoltaic development, they may extend into the viewsheds of State Routes 14 and 58. Construction of solar photovoltaic facilities would create temporary, adverse changes in the visual character of the Tehachapi area and permanent facilities have the potential to create substantial changes in the visual quality and character of the flat desert areas south of the Tehachapi Mountains. Facility elements may be visible from public vantages, particularly State Routes 14, 58, and 138, which pass directly through the area where solar photovoltaic development would occur. Residents in the community of Rosamond may be affected by construction and operation activities near State Route 14. Some recreationists in the Sierra Pelona Mountains to the south of the Tehachapi area may be affected by the change in visual character, but this would largely depend on where the recreationist is located. Because specific locations of solar photovoltaic projects are unknown, it is possible that facilities could be constructed in pristine areas, resulting in significant scenic impacts.

### *Out of State – Low and High Load Conditions*

Under the 20 percent low and high load conditions, implementation of the same degree of solar photovoltaic energy projects in Arizona/Southern Nevada—though modest—may result in significant adverse effects on scenic resources in these areas. Projects may occur on federal lands, in which case they would be subject to environmental review of aesthetic impacts under NEPA, and projects may also be subject to state environmental policies, rules, and regulations. In any case, however, implementation of solar photovoltaic projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land. Scenic impacts of solar photovoltaic development under the 20 percent RPS low and high load conditions would be significant. This impact would be expected to occur even without adoption of the RES.

## *33 Percent Renewable Electricity Standard*

### *Distributed Statewide – Low and High Load Conditions*

No additional distributed solar photovoltaic energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

### *Tehachapi – Low and High Load Conditions*

The amount of solar photovoltaic and transmission development in the Tehachapi area under 33 percent RES low and high load conditions is expected to be the same as under the 20 percent RPS high load scenario, discussed above.

### *Mountain Pass – Low and High Load Conditions*

As with solar thermal, the level of solar photovoltaic energy and transmission development in the Mountain Pass area is anticipated to remain the same under both the 33 percent low and high scenarios. Construction activities and introduction of new solar photovoltaic energy facilities into the desert landscape may impair scenic vistas, resources, and aesthetic character. These visual elements would be visible primarily to motorists traveling on Interstate 15, which passes through the Mountain Pass project area and is a popular route for travelers to Las Vegas, and recreationists at the Primm Valley Golf Course. While not a State-designated scenic highway, San Bernardino County has designated portions of Interstate 15 that pass through the area as having scenic character of visual importance. Motorists are considered to have a low sensitivity to change of existing visual character because of their distance, angle, and duration of views in this area. Construction and operation activities may also be visible to residents in the nearby community of Primm, Nevada, although views may be minimal because of the community's distance from the area.

Although some transmission lines already pass through the Ivanpah Valley, the solar thermal energy facilities would introduce new artificial elements that would contrast photovoltaic with the existing natural environment as well as strong spatial and scale dominance. The proposed project would result in a significant visual change in the site and its surroundings.

***Riverside East – Low and High Load Conditions***

As with solar thermal, a similar amount of solar photovoltaic energy and transmission development is expected to occur in the Riverside East area under the 33 percent RES low and high load conditions. Construction activities would create a temporary, adverse change in the visual character of the area due to the introduction of heavy equipment in addition to site clearing and grading activities. Operation would introduce new solar photovoltaic energy facilities into the largely undeveloped desert landscape. These visual elements would be visible primarily to motorists traveling on Interstate 10, which passes through the project area, but which is not listed as a State scenic highway. The proposed project would introduce prominent solar photovoltaic structures into the foreground of motorists and into the background of residents in the nearby City of Blythe. Some recreationists at Joshua Tree National Forest to the west of the Riverside East area may also be affected by the substantial visual change in the desert landscape. Construction and operation of solar photovoltaic development would substantially degrade the Riverside East area and its existing natural surroundings by changing the environment to an industrial landscape. This would be a significant impact.

***Fairmont –Low and High Load Conditions***

Under the 33 percent RES low and high load conditions, development of solar photovoltaic energy and transmission is expected to occur in the Fairmont area. Construction activities would create a temporary, adverse change in the visual character of the Fairmont area due to the introduction of heavy equipment, access roads in addition to site clearing and grading. Construction activities may also alter naturally vegetated areas. Operation of the proposed project would introduce new solar photovoltaic facilities into areas that are largely undeveloped or used for agricultural purposes. These visual elements may be visible to motorists traveling on State Route 138, and to a much lesser extent, on State Route 14 although views from State Route 14 may be indiscernible. The proposed project would introduce prominent structures with an industrial character into the foreground of motorists and into the background of some residents in the nearby cities of Palmdale and Lancaster and the community of Little Rock, As a result, construction and operation of solar photovoltaic facilities would substantially degrade the Fairmont area and its existing natural surroundings.

***Out of State – Low and High Load Conditions***

Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar photovoltaic would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar photovoltaic and transmission line development under the 33 percent RES low and high load conditions would be significant.

# III.B. AIR QUALITY

This section includes a general description of existing conditions (e.g., types of sensitive land uses and sources located out-of-state), a summary of applicable regulations, and evaluation of potential short-term and long-term air quality impacts associated with the out-of-state implementation of the proposed renewable energy development scenarios. Mitigation is recommended, as necessary, to reduce significant impacts.

As described in the Project Description, the RES Calculator was used to identify out-of-state electricity generation by resource type for: 2008 conditions; 20 percent RPS in 2020 under low and high load conditions; and 33 percent RES in 2020 under low and high load conditions. Tables II-1 and II-2 illustrate comparative data for 2008 (existing conditions for purposes of analysis), RPS and RES under low and high load conditions, respectively. Tables II-3 through II-6 illustrate electricity generation by resource type, by CREZ, for each scenario. Figure II-1 illustrates CREZ locations.

It is important to note that while the RES Calculator output represents the best available data to represent the results of the proposed regulation and a reasonable set of assumptions upon which to assess impacts, the manner in which renewable energy projects would actually come on line cannot be known with certainty. The number of potential future combinations of renewable resource mix, location, and timing, and degree that would satisfy RES requirements is nearly infinite and would depend upon myriad economic, political, and environmental factors. The plausible compliance scenarios identified by ARB and modeled using the RES Calculator represent a reasonable characterization of the way in which the future could unfold; analysis of additional potential future scenarios would not meaningfully add to the body of evidence necessary for ARB to make an informed decision with regard to the proposed regulation.

In addition, as with all of the environmental effects and issue areas, the precise nature and magnitude of impacts would depend on the types of projects authorized, their locations, their aerial extent, and a variety of site-specific factors that are not known at this time but that would be addressed by environmental reviews at the project-specific level.

## 1. ENVIRONMENTAL SETTING

**Note to Reader:** The evaluation of the in-State air quality impacts resulting from the renewable energy projects necessary for compliance with the RES is provided in Chapter IX of the RES Staff Report. Based on that analysis, implementation of new in-State renewable energy projects would not generate levels of emissions that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, result in a cumulatively considerable net increase in non-attainment areas, or expose sensitive receptors to substantial pollutant concentrations or odors with mitigation (e.g., compliance with applicable regulations). Thus, in-State air quality impacts from operation of renewable energy facilities is expected to result in beneficial effects. Generally, it is important to note that renewable electricity generation produces fewer pollutants per unit of electricity output than the fossil-fuel generation it would displace and less total electricity would be generated in-State in comparison to existing conditions.

Construction of any new facilities would be subject to site-specific mitigation imposed by local and potentially federal lead agencies and local air districts. Mitigation for construction related air quality impacts is expected to be the same or similar to those detailed below in Mitigation B-1. Please refer to the RES Staff report for additional information.

The following presents an evaluation of the potential out-of-state air quality impacts that could occur with implementation of the 33 percent RES.

### (a). EXISTING OUT-OF-STATE SOURCES AND SENSITIVE LAND USES

Out-of-state renewable energy resources are projected by the RES Calculator to be developed in the following general areas: Alberta, Arizona/Southern Nevada, British Columbia, Montana, New Mexico, Northwest, Reno/Dixie Valley, Utah/Southern Idaho, and Wyoming.

The existing air quality environment in the proposed out-of-state areas is influenced by stationary, area, and mobile sources. According to EPA, there are areas within those mentioned above where out-of-state renewable energy resources are projected by the RES Calculator to be developed that are currently designated as nonattainment areas for ozone (8-hour), $PM_{10}$, $PM_{2.5}$, CO, $SO_2$, and lead) (EPA 2010). Sensitive land uses in such areas may include residences (e.g., single- and multi-family), schools, hospitals, nursing homes, and other uses that may include segments of the population that are sensitive to poor air quality.

## 2. REGULATORY SETTING

The following provides a brief description of the Federal and State regulations that could be applicable to an out-of-state renewable energy project. Local regulations may also apply; however, because the specific siting of the renewable energy facilities is not known at this time it would be speculative to present a discussion of applicable local regulations.

**Table III.B-1. Applicable Laws and Regulations for Air Quality**

| Regulation | Description |
|---|---|
| **Federal** | |
| 40 Code of Federal Regulations (CFR) (National Environmental Policy Act [NEPA]) | NEPA requires all federal agencies to consider environmental factors through a systematic interdisciplinary approach before committing to a course of action. The NEPA process is an overall framework for the environmental evaluation of federal actions. |

| Table III.B-1. Applicable Laws and Regulations for Air Quality | |
|---|---|
| **Regulation** | **Description** |
| Clean Air Act and 40 CFR, Part 50 | The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) (40 CFR, Part 50) for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of NAAQS. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. EPA Office of Air Quality Planning and Standards (OAQPS) has set NAAQS for six principal pollutants, which are called "criteria" pollutants. |
| Other Applicable Federal-Level Regulations | This includes all other applicable regulations at the federal level for portions of the project area that are outside of the U.S. (e.g., Canada). |
| **State** | |
| Other Applicable State-Level Regulations | This includes all other applicable regulations at the state level for portions of the project area that are outside of California (e.g., Arizona, Nevada). |

## 3. PROJECT IMPACTS

This section describes the project's out-of-state effects on air quality for the 20 percent RPS and 33 percent RES. The discussion includes the criteria for determining the level of significance of the effects and a description of the methods and assumptions used to conduct the analysis.

As with all of the impacts, the precise magnitude and extent of the impact would depend on the type of renewable energy project authorized, its specific location, its total length and size, and a variety of site-specific factors that are not known at this time. All of these issues would be addressed through project-specific environmental reviews that would be conducted by local land use agencies (e.g., cities, counties) or other regulatory bodies at such time the projects are proposed for implementation. ARB would not be the agency responsible for conducting the project-specific environmental review because it is not the agency with authority for making land use decisions.

## (a). METHODOLOGY

Potential out-of-state impacts to air quality were assessed based on the potential for the 33 percent RES to exceed the thresholds of significance identified below. The analysis that is presented below evaluates the change from existing conditions to the 33 percent RES in 2020. However, an incremental portion of these impacts would occur regardless of whether the 33 percent RES is implemented. The CPUC approved the 20 percent RPS and this regulation would be implemented by 2020. The 33 percent RES would further the renewable energy objective and would be added to the 20 percent RPS. Therefore, the analysis below describes the impacts that would occur under the 20 percent RPS, the total impacts that would occur under the 33 percent RES (i.e., existing conditions to 33 percent RES), and the incremental impacts from 20 percent RPS to 33 percent RES. For each of these alternatives, a high and low load scenario is also evaluated (see Section II, Project Description, for additional details).

For some impacts below, the same type and magnitude would occur under each scenario and each alternative. Where this occurs, a combined analysis is presented to streamline the presentation of environmental impacts to avoid unnecessary repetition.

## (b). THRESHOLDS OF SIGNIFICANCE

For purposes of this analysis, the following applicable thresholds of significance were used to determine whether implementing the 33 percent RES would result in a significant air quality impacts. The project would result in a significant impact if it would:

- conflict with or obstruct implementation of the applicable air quality plan;
- violate any air quality standard or contribute substantially to an existing or projected air quality violation;
- Result in a cumulatively considerable net increase of any criteria air pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard;
- Expose sensitive receptors to substantial pollutant concentrations; or
- Create objectionable odors affecting a substantial number of people.

**IMPACT B-1**

**Short-Term Construction Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because the specific air quality impacts of the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).**

## All Renewable Energy Project Types

All renewable energy projects no matter their size, out-of-state location, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in short-term construction air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for short-term construction emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

During construction of renewable energy projects out-of-state, criteria air pollutant and precursor emissions could be generated from a variety of construction activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would generate fugitive PM dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (including $PM_{10}$ and $PM_{2.5}$) vary as a function of parameters such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. Exhaust emissions from construction-related mobile sources also include ROG and $NO_x$ emissions. These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. Criteria air pollutants that are also associated with localized concerns (e.g., CO) are discussed under Impact B-3 below.

The site preparation phase typically generates the most substantial emission levels because of the on-site equipment and ground-disturbing activities associated with grading, compacting, and excavation. Site preparation equipment and activities typically include backhoes, bulldozers, loaders, and excavation equipment (e.g., graders and scrapers). Although detailed construction specific information is not available at this time, based on the types of renewable energy projects listed in the Section II, Project Description it would be expected that the primary sources of construction-related emissions include soil disturbance- and equipment-related activities (e.g., use of backhoes, bulldozers, excavators, and other related equipment). Based on typical emission rates and default parameters for above mentioned equipment and activities, construction of a out-of-state renewable energy project could result in hundreds of pounds of daily $NO_x$ and $PM_{10}$, which may exceed general mass emissions limits depending on the exact location of generation. Thus, because the specific air quality impacts of renewable energy projects necessary to comply with the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES, as, based on the modeling, the magnitude of electricity generated from new out of-state renewable projects is relatively similar (e.g., approximately 9,500 GWh versus 10,900 GWh under both low and high load scenarios). Additionally, the magnitude of this impact is influenced more by the how (e.g., size of project footprint and types of construction activities required) and the where (e.g., whether located in a nonattainment area) of the new renewable projects, more so than the total amount of electricity generated.

**IMPACT B-2**

**Long-Term Operational Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because renewable generation produces lower levels criteria air pollutants per unit of electricity output than fossil-fuel generation it would displace and less total electricity would be generated out-of-state in comparison to existing conditions, these projects would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). This impact is considered *less than significant* for all renewable energy types under the 33 percent RES (high and low load).**

## All Renewable Energy Project Types

All renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in long-term operational air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, as discussed with regards to the in-state projects, renewable generation produces less criteria air pollutants per unit of electrical output than fossil-fuel generation it would displace with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions). Additionally, in comparison to existing conditions less total electricity would be generated out-of-state under the 33 percent RES (e.g., approximately 98,000 GWh versus 60,000 under the low load scenario and 86,000 under the high load scenario). Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought. Thus, project-generated long-term operational emissions of criteria air pollutants would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES (e.g., in comparison to existing conditions less total electricity would be generated out-of-state under both the low and high load scenarios). This impact is considered less than significant for all renewable energy types under the 33 percent RES (high and low load).

| | |
|---|---|
| **IMPACT B-3** | **Impacts to Sensitive Receptors in the Project Area from Exposure to Substantial Pollutant Emissions (e.g., localized criteria air pollutants, toxic air contaminates) and Odors. Because the specific out-of-state air quality impacts of the 33 percent RES cannot be identified with any certainty, and these projects could potentially expose sensitive receptors to substantial localized criteria air pollutants, toxic air contaminants , or odors, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).** |

## All Renewable Energy Project Types

As discussed above under Impact B-1, all renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in the exposure of sensitive receptors to air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for the exposure of sensitive receptors to substantial emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

The primary criteria air pollutant of localized concern is CO. Local mobile-source CO emissions near roadway intersections are a direct function of motor vehicle activity, particularly during peak commute hours, including traffic volume, speed, and delay. Transport of CO is extremely limited because it disperses rapidly with distance from the source under normal meteorological conditions. Under specific meteorological conditions, CO concentrations near roadways and/or intersections may reach unhealthy levels with respect to local sensitive land uses, such as residential areas, schools, playgrounds, childcare facilities, and hospitals. Consequently, CO emissions are typically analyzed at a local rather than a regional level. Additionally, because increased CO concentrations are usually associated with roadways that are congested and with heavy traffic volume, the criteria to determine if project-generated emissions would result in the exposure of sensitive receptors to substantial pollutant concentrations is tied the project’s effect on the delay times and LOS of local intersections.

As discussed in Section M, Transportation and Traffic, although detailed information is not currently available, renewable energy projects would be anticipated to result in short-term construction and long-term operational traffic from worker commute-, maintenance/operation-, and material delivery-related trips. The amount of construction activity would fluctuate depending on the particular type, number, and duration of usage for the varying equipment; and the phase of construction (e.g., demolition, construction, erection). These variations would affect the amount of project-generated traffic for both worker commute trips and material deliveries. The amount of operational traffic would also vary depending on the size and type of renewable energy project. Thus, depending on the amount of trip generation and the location of the renewable energy project, implementation could conflict with applicable programs, plans, ordinances, or policies, specifically the degradation of delay times and LOS of local intersections, which are tied as discussed above to localized CO impacts. Long-term operation of stationary sources could also result in localized CO emissions at sensitive receptors if located at close distance to new renewable energy projects.

During construction of renewable energy projects out-of-state, toxic air contaminants (TACs) could be generated from a variety of construction activities, but primarily composed of exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips. Construction activities could be located in areas where naturally occurring substances are present in the soil, thatif These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. The amount of TAC’s and associated unit risk factors from operational activities would also vary depending on the size and type of renewable energy project. Even though project implementation would be anticipated to produce less TACs overall due to the fact renewable energy production produces less TAC’s per unit of electricity output than the fossil-fuel generation it would displace under the plausible compliance scenarios, the exposure of sensitive receptors is highly dependent on the their distance from the source.

With regards to both project-generated construction and operational TAC emissions, the dose to which receptors are exposed is the primary factor used to determine health risk. Dose is a function of the concentration of a substance or substances in the environment, which is positively correlated with distance from the source, and the duration of exposure to the substance. Thus, a new renewable energy project could be located in an area where sensitive receptors are currently located and no current sources exist, resulting in a net increase in exposure from project implementation.

Lastly, though the types of renewable energy projects listed in the Project Description would not be anticipated to result in any construction-related odor emissions, long-term operational activities could depending on the exact type of stationary sources on-site. Even diesel emissions at a close distance could be considered an objectionable odor source.

In summary, the specific location, type, and number of renewable energy projects constructed out-of-state is not known at this time. However, construction and operational activities could result in the generation of localized CO emissions, TACs, and odors. Thus, because the specific air quality impacts of new renewable projects needed to comply with the 33 percent RES cannot be identified with any certainty, and activities associated with these projects, depending on the exact location of the renewable energy projects in relation to existing sensitive receptors, could result in the exposure thereof to substantial pollutant concentrations or odors, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the out-of-state impacts that would occur under the 20 percent RPS versus the 33 percent RES.

## 4. MITIGATION

Mitigation is required for the following significant or potentially significant impacts.

### Mitigation Measure B-1

- **Proponents for the proposed renewable energy project shall coordinate with local land use agencies to seek entitlements for development of the project including completing all necessary environmental review requirements (e.g., NEPA). The local land use agency or governing body shall certify that the environmental document was prepared in compliance with applicable regulations and shall approve the project for development.**

- **Based on the results of the environmental review, proponents shall implement all mitigation identified in the environmental document to reduce or substantially lessen the environmental impacts of the project.**

- **Comply with local plans, policies, ordinances, rule, and regulations regarding air quality-related emissions and associated exposure.**

- **Apply for, secure, and comply with all appropriate air quality permits for project construction and operations from the local agencies with air** quality jurisdiction and from other applicable agencies (e.g., EPA), if appropriate, prior to construction mobilization.

- Prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented. Implementation of the above mitigation would reduce this impact to a less-than-significant level

for all renewable energy types under the 33 percent RES plausible compliance scenarios (high and low load conditions).

### Mitigation Measure B-2

- Implement Mitigation M-1 above.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented.

Implementation of the above mitigation would reduce this impact to a less-than-significant level for all renewable energy types under the 33 percent RES (high and low load conditions).

# ATTACHMENT U

**BEFORE THE BOARD OF SUPERVISORS**
**COUNTY OF KINGS, STATE OF CALIFORNIA**

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|---|---|---|
| **IN THE MATTER OF AMENDING THE LOCAL CEQA GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS FOR THE COUNTY OF KINGS.** | ) ) ) ) ) ) | **RESOLUTION NO. <u>16-001</u>**<br><br>**RE: Local Guidelines for the Implementation of CEQA** |

**WHEREAS,** pursuant to Section 21082 of the Public Resources Code of the State of California all public agencies are required to adopt by ordinance, resolution, rule or regulations, objectives, criteria, and procedures for the evaluation of projects, and the preparation of environmental impact reports and negative declarations under the provisions of the California Environmental Quality Act (hereinafter referred to as "CEQA", and found at Public Resources Code Section 21000 et seq; all generic "Section" references are to the Public Resources Code); and

**WHEREAS,** Section 21082 further requires that the objectives, criteria, and procedures adopted by a public agency shall be consistent with the provisions of CEQA and with the State CEQA Guidelines adopted by the Secretary of the Resources Agency pursuant to CEQA (as found in the California Code of Regulations, Title 14, Division 6, Chapter 3, and hereinafter referred to as the "CEQA Guidelines"); and

**WHEREAS,** the purpose of this Resolution is to further streamline the local CEQA process by rescinding in its entirety Resolution No. 09-001, adopted January 27, 2009, entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings", and replacing it with the local guidelines for the implementation of CEQA set forth in Attachment A.

**NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:**

1. This action is exempt pursuant to <u>Section 15061(b)(3)</u> of the *Guidelines* for *California Environmental Quality Act* (*CEQA Guidelines*). This section states that a project is exempt from *CEQA* if the activity is covered by the general rule that *CEQA* applies only to projects, which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to *CEQA*. The CEQA Implementation procedures are technical changes concerning general policy for the implementation of CEQA and there is no possibility that adopting these procedures will have a significant effect on the environment..

2. Except as otherwise expressly provided herein, the provisions of CEQA and the CEQA Guidelines are hereby referred to, adopted and made part of this Resolution and a part of the Local Guidelines as hereinafter defined, with the same effect as if fully set forth herein, and all the provisions thereof shall apply to projects proposed to be carried out or given discretionary review and approval by the County of Kings or any organizational subdivision thereof.

3. Resolution No. 09-001 entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings" is hereby rescinded in its entirety.

4. The local guidelines in Attachment A of this Resolution are hereby enacted to implement the provisions of the California Environmental Quality Act in the County of Kings (such local guidelines are herein referred to as the "Local CEQA Guidelines").

The foregoing Resolution was passed and adopted on a motion by Supervisor Fagundes, seconded by Supervisor Neves, by said Board of Supervisors at a regular meeting held on the 5th day of January, 2016, by the following vote:

**AYES:** **Supervisors Fagundes, Neves, Valle, Pedersen, Verboon**
**NOES:** **None**
**ABSENT:** **None**

Doug Verboon

Chairman of the Board of Supervisors
County of Kings, State of California

**WITNESS** my hand and seal of said Board of Supervisors this 5th day of January, 2016.

Melanie Curtis

Melanie Curtis
Deputy Clerk of said Board of Supervisors

# ATTACHMENT A

# LOCAL GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS IN THE COUNTY OF KINGS, CALIFORNIA

**Section 1. Purposes.**

These Local Guidelines implement the provisions of the California Environmental Quality Act (CEQA) as contained in Division 13 (commencing at Section 21000) of the Public Resources Code of the State of California and the State CEQA Guidelines, as contained in Chapter 3 (commencing at Section 15000), Division 6, Title 14 of the California Code of Regulations, as adopted by the Secretary of the Resources Agency of the State of California. These Local Guidelines do not apply to ministerial projects, or to those projects which are statutorily exempt or excluded from CEQA review requirements, as set forth in Public Resources Code sections 21080 through 21080.35, or to those projects which are categorically exempt under the provisions of Article 19 (commencing at Section 15300) of the State CEQA Guidelines, or to those projects which are emergency projects under the provisions of Section 15269 of the State CEQA Guidelines.

**Section 2. Definitions.**

Whenever the following words or phrases are used in these Local Guidelines, unless otherwise defined, they shall have the meaning ascribed to them in this Section. These definitions are intended to clarify but not to replace or negate the definitions used in CEQA or in the State CEQA Guidelines, beginning at Section 15350, which are included herein by reference.

**a. Consultant.** An individual consultant or a consulting firm with expertise in environmental sciences and the preparation of environmental documents.

**b. County or County Department.** County or County Department means Kings County and any organizational subdivision thereof.

**c. EAC - Environmental Advisory Committee - Committee.** An informal committee appointed by the Board of Supervisors to advise County boards, commissions, committee, and departments on environmental matters, associated with their individual areas of expertise, concerning the implementation of CEQA, made up of the following members:

Kings County Health Officer,
Kings County Community Development Agency Director,
Kings County Director of Public Works,
Kings County Agricultural Commissioner and Sealer of Weights and Measures,
U.C. Cooperative Extension Services Farm Advisor, and
The Manager of the Kings Mosquito Abatement District.

**d. Professional Services Agreement.** An agreement between the County and a consultant which specifies the work that will be performed for the preparation of environmental documents and the cost of preparing such a document.

**e. Reimbursement Agreement.** An agreement between the County and the project proponent to reimburse the County for the actual cost to prepare the environmental documents for the project, including the cost of the "Agreement for Professional Services" and administrative costs incurred by County staff in processing the project.

**f. Indemnification Agreement.** An agreement between the County and the project proponent to reimburse the County's actual cost associated with challenges to the environmental documents prepared by, or under the direction of, the County for the project and to defend and indemnify the County against any and all challenges to the County's review, consideration, processing or approval of the project application.

**g. Faithful Performance/Payment Bond.** A performance bond, payment bond, cash deposit, letter of credit, or other suitable financial instrument approved by the County that is convertible to cash, or any combination of the above,, provided by the applicant to ensure the faithful performance of the project proponent's obligations, and/or the payment of amounts due, under a Reimbursement Agreement and/or an Indemnification Agreement entered into between the County and the Project Proponent under the terms and provisions of these Local Guidelines.

**Section 3. Kings County Environmental Advisory Committee (EAC).**

a. The Kings County Environmental Advisory Committee EAC shall consist of the following six members:

   Kings County Health Officer,
   Kings County Community Development Agency Director,
   Kings County Director of Public Works,
   Kings County Agricultural Commissioner and Sealer of Weights and Measures,
   U.C. Cooperative Extension Services Farm Advisor, and
   The Manager of the Kings Mosquito Abatement District.

b. The EAC shall be advisory only and will not hold public meetings. Each EAC member may provide written comments determined by the member to appropriately reflect that member's general and specific environmental concerns related to his or her area of expertise.

c. Duties of the Members of the EAC: The principal duty of the members of the EAC shall be to review initial studies which are submitted by County Departments during the 20-day public review period for proposed negative declarations and the 30-day or 45-day public review period for draft EIRs required by CEQA Section 21091. Committee members may make any of the following recommendations:

   1) Recommend approval of the initial study as a negative declaration, if, based upon the initial study, the Committee member determines that the project will not have a significant effect on the environment. Failure to notify the Planning Division of the Community Development Agency within the specified review period, indicates acceptance of the initial study as submitted; or

   2) In writing, request specific changes to the draft initial study, and with those specified changes recommend that the decision maker adopt a negative declaration; or

   3) In writing, recommend the preparation of an environmental impact report if, based upon the initial study, the Committee member believes that the project will have a significant adverse effect on the environment. The committee member shall specify, in writing, what effects on the environment he or she believes will be significant and why.

d. Each EAC member shall also be responsible for recommending to the Board of Supervisors' requests for additions to, or deletions from, the list of classes or projects that are exempt from environmental review pursuant to Sections 21084 through 21086, inclusive, of CEQA.

e. Limitations of Review by Environmental Advisory Committee: The review of negative declarations and environmental impact reports by the members of the EAC shall be advisory in nature and shall be limited to a determination of the objectivity and adequacy of the environmental documents submitted to its members, and shall ensure that the decision maker has sufficient information about the possible impacts to the environment, in the judgment of the committee member, that the project may cause. Committee members shall not consider the value of the project itself or whether the project should be approved or denied. Such determination is solely the responsibility of the decision maker for the project.

**Section 4. Ministerial Projects and Actions in Kings County**

Section 21080(b)(1) of CEQA provides that the Act does not apply to ministerial projects proposed to be carried out or approved by public agencies. Section 15268 of the State CEQA Guidelines states that the determination of what is "ministerial" can most appropriately be made by the public agency involved, and that each public agency should identify or itemize those projects and actions which are deemed ministerial.

The following is a non-exclusive list of types of projects that are ministerial and therefore exempt from CEQA review requirements:

**a. Sheriff-Animal Control**

1. Dog Licenses

**b. Agricultural Commissioner-Sealer**

1. Agricultural crop moving permits

**c. Building Division of the Community Development Agency**

1. Plan check reviews
2. Building Permits (including Electrical, Plumbing, and Mechanical Permits)
3. Demolition Permits
4. Mobile Home Installation Permits
5. Relocation Inspections and Permits
6. Utility Service Connections and Disconnections
7. Compliance Inspections and Reports
8. Water well permits

**d. County Clerk**

1. Marriage Licenses

**e. Fire Department**

1. Fireworks Sales Permits
2. Weed Abatement Program

**f. Health Department**

1. Food Vendor's Permits
2. Water Supply Permits (small public water systems and state small water systems)
3. Underground Storage Tank Permits, Authority to Construct, and Authority to Abandon
4. Hazardous Materials Business Plan and Inventory approvals
5. Risk Management and Prevention Program approvals
6. Medical Waste Management Registrations
7. Limited Quantity Medical Waste Hauler Exemptions
8. Registration of businesses engaged in the cleaning of septic tanks, chemical toilets, cesspools, and seepage pits
9. Reserved.
10. Plan approval for construction, modification, or remodeling of food facilities, public swimming pools and spas, on site sewage disposal systems, small public water systems, state small water system and/or underground storage tanks (including piping)
11. Occupational health and safety consultation services
12. Body art registrations

**g. Planning Division of the Community Development Agency**

1. Site Plan Reviews conducted by the Zoning Administrator under the provisions of Article 16 of the Kings County Development Code.
2. Land divisions exempted by Sections 2306 and 2308.I of Article 23 of the Kings County Development Code.
3. Certificates of Compliance
4. Lot Line Adjustments
5. Annual Fire Arms Dealers Reviews
6. Code enforcement investigations and orders for abatement of nuisances and violations
7. Abandoned Vehicle Abatement Program investigations and orders for abatement
8. Certificates of Voluntary Parcel Merger
9. Temporary Use Permits

**h. Public Works Department**

1. Encroachment Permits
2. Moving permits
3. Traffic control activities

**i. Tax Collector**

1. Dance, explosive, gun, and solicitors licenses
2. Rubbish disposal operator's license

A notice of exemption shall be filed for all projects determined to be statutorily, categorically or otherwise exempt from CEQA environmental review.

**Section 5. Initial Study.**

The initial study process shall be conducted according to the procedures outlined in the State CEQA Guidelines, Article 5, beginning with Section 15060.

The County department initiating a public project or receiving an application for discretionary approval of a private project may prepare its own initial study, or submit a description of the project to the Planning Division of the Community Development Agency for environmental review. If a project description is submitted to the Planning Division, the Planning Division shall conduct an initial study pursuant to Section 15063 of the State CEQA Guidelines and these Local Guidelines to determine if the project may have a significant effect on the environment. The County department or the applicant shall provide any additional information the Planning Division may require in preparing the initial study. Failure to provide the requested information in a timely manner may cause the application not to be certified as complete, and delay the development of the required environmental documents.

**Section 6. Time Limits for the Certification of Environmental Documents.**

Pursuant to Section 21151.5 of CEQA and Article 8 of the State CEQA Guidelines, the County of Kings hereby establishes one year as the time limit for the completion and certification of environmental impact reports, and 180 days for the completion and adoption of negative declarations, for projects which require environmental review. The commencement and running of these time periods shall be governed by CEQA and the CEQA Guidelines.

Extensions of Time for EIR's: Extensions of time for the processing of EIR's may be approved once, for an additional period not to exceed 90 days, by the Lead Agency provided that it finds that compelling circumstances justify the extension of time and that the project applicant consents to the specified extension, pursuant to Government Code Section 65957 and State CEQA Guidelines Section 15108. Extensions exceeding 90 days may be approved where the law expressly otherwise provides for such additional extensions.

**Section 7. Deposit and Accounting on Private Project.**

All applications for the discretionary review of private projects by the County shall include a fee, subject to Section 21089 of CEQA, in an amount set by Ordinance of the Kings County Board of Supervisors, at the time the project application is filed with the Planning Division of the Community Development Agency to cover the cost of preparation of the initial study.

If it is determined that an EIR should be prepared, the applicant shall be required to pay the cost of preparing the EIR (see Section 2 d, e, f, and g above). The Planning Division shall ensure the EIR is prepared according to the procedures described in Article 7 (Section 15084 through 15097) of the CEQA Guidelines.

The Planning Division may prepare the required documents, with Board of Supervisors approval, by engaging the services of a consultant with expertise in preparing environmental documents, based on a detailed work plan approved by the Planning Department staff, and made a part of the "Agreement for Professional Services", shall be submitted to the project applicant who shall enter into a *Reimbursement Agreement* with the County and deposit in an interest bearing account in the County Treasury the amount of the cost shown in the detailed work plan (agreement), plus an administrative fee determined by the Community Development Agency Director to be necessary to defray the cost of administering the agreement with the consultant and the staff time necessary to process the project to its completion.

As an alternative the applicant may submit detailed information in any form, including the form of a draft EIR. The Planning Division, with Board of Supervisors approval, may engage at the expense of the applicant the services of a consultant with expertise in preparing environmental documents, to advise the County on the adequacy of the information submitted, including, but not limited to, a draft EIR, if any is submitted. Reimbursement for the costs of the County's consultant shall be the same as described above.

An accurate accounting shall be kept by the Planning Division, with assistance from the County Department of Finance, of the actual cost of preparing and administering the EIR and shall be made available to the applicant at his request. Upon the completion of the project, after the decision maker's final action, the Planning Division shall refund to the applicant any money remaining in the account, including interest that was earned and not used.

**Section 7.5. Indemnification and Bonding.**

In its sole and absolute discretion, the County may determine that it has exposure to potential extraordinary costs and require an applicant to provide the county indemnification against extraordinary costs associated with the review and processing of a development application. The extraordinary costs the County may incur associated with the review and processing of a development application, may include, but are not limited to, applications for development entitlements requiring preparation of environmental impact reports, specific plans, and major general plan amendments, large urban development projects, project decisions that are appealed or challenged through law suits, etc. In addition, if it is determined that an Indemnification Agreement is required, the applicant will be required to provide a bond in an amount sufficient to ensure that the applicant's indemnification of the County is sufficient to protect the public interest in case of challenges to the process or action of the County related to the project, or failure of the applicant to provide the County with required reimbursements for the cost of the application review and processing under the terms of the Reimbursement Agreement. In its sole and absolute discretion, the County may determine that the Reimbursement Agreement and the Indemnification Agreement be combined as one document. The form, nature and amount of the bond and/or bonds or other suitable financial instrument, required under the terms of these Local Guidelines and in the light of any risks associated with a particular project shall be in the sole and absolute discretion of the County.

**Section 8. Action by the Decision-Maker.**

(a) When a proposed negative declaration has been forwarded to the decision-maker, the decision-maker shall, prior to making a decision on the project, either approve the negative declaration based upon a finding that the project will not have a significant effect on the environment, or shall refer the matter to the Planning Division of the Community Development Agency for preparation of an EIR, or mitigated negative declaration, based upon a finding that the project may have a significant effect on the environment. If the matter is referred for additional review, the decision maker shall take no further action on the project until a final EIR, or mitigated negative declaration, has been prepared as required by law.

(b) When a final EIR has been prepared and processed according to Article 7, beginning with Section 15080 of the State CEQA Guidelines, the decision-maker shall, prior to making a decision on the project, certify that the final EIR has been completed in compliance with CEQA and the State CEQA Guidelines, and shall review and consider the information contained in the final EIR. Based upon information contained in the final EIR, when the decision-maker finds that the project will have a significant effect on the environment, the decision-maker shall state in writing reasons to support its decision to approve or carry out the project based upon information contained in the final EIR or other information contained in the record.

**Section 9. Mitigation Reporting and Monitoring Program.**

When approving projects for which mitigation measures are required and adopted, the decision maker shall adopt as part of the approval action a "Mitigation Reporting and Monitoring Program", pursuant to Section 21081.6 of CEQA and Section 15097 of the State CEQA Guidelines, for the changes to the project. The "Mitigation Reporting and Monitoring Program", then becomes a condition of approval to mitigate or avoid significant effects on the environment. Failure of the project applicant to comply with the reporting requirements and mitigation measures are grounds for permit revocation or correcting the effects on the environment at the project applicant's cost.

The decision maker may require the applicant to deposit an amount of money estimated to offset the cost of monitoring the development and operation of the project into an interest bearing account in the Kings County

Treasury. Upon completion of the monitoring program any unused money in the account shall be returned to the applicant.

**Section 10. Notice of Determination.**

After making a decision on a project, the decision-maker shall cause to be filed a Notice of Determination, pursuant to Section 21080.4 of CEQA and 15094 of the State CEQA Guidelines. Such notice shall include a brief description of the project, the decision of the decision-maker to approve (carry out) or disapprove (not carry out) the project, the determination of the decision-maker whether the project will or will not have a significant effect on the environment, and a statement whether an environmental impact report has been prepared. The Planning Division of the Community Development Agency shall ensure that such notices are filed.

**Section 11. Duties of the County Clerk.**

All notices submitted to the County Clerk pursuant to CEQA shall posted by the County Clerk at the place designated by the County Clerk for the posting of all official notices. Members of the general public requesting copies of said notices shall be charged for the actual cost of reproducing that copy. The County Clerk shall prepare and maintain a list of the names and mailing addresses of all persons requesting review of a particular notice.

**Section 12. Severability.**

If any provision of these Local Guidelines or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions or applications of these Local Guidelines which can be given effect without the invalid provision of application thereof, and to this end the provisions of these Local Guidelines are severable.

**END OF GUIDELINES**

# ATTACHMENT V

## Notice of Exemption

**TO:** ☐ Office of Planning and Research

| *For U.S. Mail* | *Street Address* |
|---|---|
| P.O Box 3044, Room 113 | 1400 Tenth St. |
| Sacramento, CA 95812-3044 | Sacramento, CA 95814 |

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

**FROM:** Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

ORIGINAL FILED
DEC 07 2023
KRISTINE LEE
KINGS COUNTY CLERK

**PROJECT TITLE:**
Site Plan Review No. 23-14 (Felicita Dairy)

**PROJECT APPLICANT:**
4-Creeks, Cole Martin, 324 S. Santa Fe St., Visalia, CA 93292
(559) 802-3052

**PROJECT LOCATION - Specific:**
22154 4th Ave.

**PROJECT LOCATION - City**
Hanford

**PROJECT LOCATION - County:**
Kings

**DESCRIPTION OF PROJECT:**
The applicant is proposing to construct a new anaerobic digester and ancillary equipment at the existing Felicita Dairy, located at 22154 4th Ave., Hanford, Assessor's Parcel Number 028-280-011. The proposed application includes the installation of a 360' L x 175' W x 25' D anaerobic digester and ancillary equipment. The biogas produced by the digester is proposed to be transported through a low-pressure pipeline to an onsite biogas conditioning pad for cooling and compression prior to entering the biogas collection line. It will then be transported to a centralized biogas upgrading facility, located on Assessor's Parcel Number 228-090-009 in Tulare County (Tulare County Special Use Permit No. PSP 18-015), for conditioning and electrical generation.

**NAME OF PUBLIC AGENCY APPROVING PROJECT:**
Kings County Community Development Agency, 1400 W. Lacey Blvd., Building 6, Hanford, CA 93230, (559) 852-2670

**NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:**
Gerrit DeJong, Felicita Dairy, 22154 4th Ave., Hanford, CA 93230, (559) 992-3272

**EXEMPT STATUS:** *(check one)*
- ☒ Ministerial (Section 21080(b)(1); 15268);
- ☐ Declared Emergency (Section 21080(b)(4); 15269(a));
- ☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
- ☐ Categorical Exemption. State type and section number: ______________
- ☐ Statutory Exemptions. State code number: ______________

**REASONS WHY PROJECT IS EXEMPT:**
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

**CONTACT PERSON:**
Noelle Tomlinson

**TELEPHONE NUMBER:**
(559) 852-2697

Signature: Noelle Tomlinson
Title: Planner
Date: 12/7/23

**Clerk/Recorder,, Kristine Lee** Date: 12/07/2023 09:09 AM

**Kings County**

**Receipt Detail**

## Receipt Information

| | | | | | |
|---|---|---|---|---|---|
| **Receipt Time:** | 12/7/2023 9:08:18 AM | **Receipt #:** | 19471 | | |
| **Location:** | MAIN OFFICE | **Department:** | REAL ESTATE | **Device:** | VIRGINIA DENKER |
| **Effective Date:** | | **User:** | R069 | | |
| **Customer:** | 4-CREEKS COLE MARTIN | | | | |
| **Address1:** | | | | | |
| **Address2:** | | | | | |
| **City:** | | **State:** | | **Zip:** | |
| **Phone:** | | **Email Address:** | | | |
| **Remarks:** | | | | | |
| **Change Issued:** | $0.00 | **Refund:** | $0.00 | **Surplus:** | $0.00 |
| **Cash Total:** | $0.00 | **Check Total:** | $70.00 | **Escrow Total:** | $0.00 |
| **VoucherTotal:** | $0.00 | **Credit Card Total:** | $0.00 | **Legalease Total:** | $0.00 |

## Revenue Information

| Seq # | No Fee | Voucher | Reference # | Transaction Type | # Pages | Amount | SubSystem Id |
|---|---|---|---|---|---|---|---|
| 1 | N | N | NA-15560147 | Noe | 1 | $70.00 | CASHADMIN |

## Payment Information

| # | Type | Payment ID # | Amount | NSF |
|---|---|---|---|---|
| 1 | CHECK | 5001 | $70.00 | |

## Revenue Detail Information

| Seq # | GL Seq | Revenue Account # | Amount | Payment # | Payment Type | Amount Paid | Amount Remaining |
|---|---|---|---|---|---|---|---|
| 1 | 1 | DFW CLERK FILING FEE | $70.00 | 1 | CHECK | | |

## Account Transaction Information

| Account # | Revenue # | GL Seq | Amount | Transaction Type | Reference # | Transaction Time |
|---|---|---|---|---|---|---|

# ATTACHMENT W

# Notice of Exemption

ORIGINAL
FILED

MAY 15 2023

KRISTINE LEE
KINGS COUNTY CLERK

**TO:** ☐ Office of Planning and Research

| *For U.S. Mail* | *Street Address* |
|---|---|
| P.O Box 3044, Room 113 | 1400 Tenth St. |
| Sacramento, CA 95812-3044 | Sacramento, CA 95814 |

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

**FROM:** Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

**PROJECT TITLE:**
Site Plan Review No. 22-16 (Countryside Dairy)

**PROJECT APPLICANT:**
Lauren Duggan, 2711 Meadow View Dr. suite 100 Redding CA 96002

**PROJECT LOCATION - Specific:**
21256 4th Ave

**PROJECT LOCATION - City**
Corcoran

**PROJECT LOCATION - County:**
Kings

**DESCRIPTION OF PROJECT:**
The applicant is proposing to establish a covered anaerobic digester and ancillary biogas cleanup equipment incidental to an existing dairy facility, Countryside Dairy, located at 21256 4th Ave, Corcoran Assessor's Parcel Number 028-280-018. There are two proposed options for the cleanup equipment – Option A (Trucking Biogas) and Option B (Piping Biogas).

**NAME OF PUBLIC AGENCY APPROVING PROJECT:**
Kings County Community Development Agency

**NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:**
David & Arlene Bakker, Lauren Duggan, Maas Energy, 2711 Meadow View Dr. suite 100 Redding CA 96002 (530) 710-8545

**EXEMPT STATUS:** (*check one*)

☒ Ministerial (Section 21080(b)(1); 15268);
☐ Declared Emergency (Section 21080(b)(4); 15269(a));
☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
☐ Categorical Exemption. State type and section number: ______________________
☐ Statutory Exemptions. State code number: ______________________

**REASONS WHY PROJECT IS EXEMPT:**
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

**CONTACT PERSON:**
Alex Hernandez

**TELEPHONE NUMBER:**
(559) 852-2679

Alex Hernandez

Signature: Alex Hernandez
Title: Deputy Director - Planning
Date: 05/15/23

KINGS COUNTY CLERK-RECORDER
1400 W. LACEY BLVD.
HANFORD, CA 93230
(559) 582-3211 X2470

---

Receipt Time: 05/15/2023 12:26:35 PM Receipt #: 8153
Issued To: LAUREN DUGGAN

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## Documents

| # | Type | # Pages | Quantity | Reference # | Book / Page | Amount |
|---|---|---|---|---|---|---|
| 1 | NOTICE OF EXEMPTION | 1 | 1 | NA-15413505 | | $65.00 |
| | | | | | Total : | $65.00 |

## Payments

| # | Type | Payment # | | Amount | NSF |
|---|---|---|---|---|---|
| 1 | CHECK | 11123 | | $65.00 | |
| | | | Total Payments: | $65.00 | |

SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY)

THANK YOU!

R066

**Clerk-Recorder,, Kristine Lee**
**Kings County**
**Receipt Detail**

Date: 05/15/2023 12:36 PM

## Receipt Information

| | | | | | |
|---|---|---|---|---|---|
| **Receipt Time:** | 5/15/2023 12:26:35 PM | **Receipt #:** | 8153 | | |
| **Location:** | MAIN OFFICE | **Department:** | REAL ESTATE | **Device:** | ALEJANDRA ESPINOZA |
| **Effective Date:** | | **User:** | R066 | | |
| **Customer:** | LAUREN DUGGAN | | | | |
| **Address1:** | 2711 MEADOW VIEW DR | | | | |
| **Address2:** | SUITE 100 | | | | |
| **City:** | REDDING | **State:** | CA | **Zip:** | 96002 |
| **Phone:** | | **Email Address:** | | | |
| **Remarks:** | SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY) | | | | |
| **Change Issued:** | $0.00 | **Refund:** | $0.00 | **Surplus:** | $0.00 |
| **Cash Total:** | $0.00 | **Check Total:** | $65.00 | **Escrow Total:** | $0.00 |
| **VoucherTotal:** | $0.00 | **Credit Card Total:** | $0.00 | **Legalease Total:** | $0.00 |

## Revenue Information

| Seq # | No Fee | Voucher | Reference # | Transaction Type | # Pages | Amount | SubSystem Id |
|---|---|---|---|---|---|---|---|
| 1 | N | N | NA-15413505 | Noe | 1 | $65.00 | CASHADMIN |

## Payment Information

| # | Type | Payment ID # | Amount | NSF |
|---|---|---|---|---|
| 1 | CHECK | 11123 | $65.00 | |

## Revenue Detail Information

| Seq # | GL Seq | Revenue Account # | Amount | Payment # | Payment Type | Amount Paid | Amount Remaining |
|---|---|---|---|---|---|---|---|
| 1 | 1 | DFW CLERK FILING FEE | $65.00 | 1 | CHECK | | |

## Account Transaction Information

| Account # | Revenue # | GL Seq | Amount | Transaction Type | Reference # | Transaction Time |
|---|---|---|---|---|---|---|

# ATTACHMENT X

# So. Tulare Biogas Gathering Line

## Summary

**SCH Number**
2020080277

**Public Agency**
Tulare County

**Document Title**
So. Tulare Biogas Gathering Line

**Document Type**
NOE - Notice of Exemption

**Received**
8/18/2020

**Posted**
8/18/2020

**Document Description**
CalBioGas South Tulare LLC proposes to construct 8.8 miles of a pressurized underground gas pipeline within portions of the County of Tulare rights-of-way of Roads 96, 128, 132 and 152; Avenues I84, 192 and 208; and Spacer Drive D 134), south of the City of Tulare. The intent of the project is to transport dairy biogas from participating dairies to a Southern California Gas Company mainline tie-in facility. The scope of the project consists of the installation of HDPE PE4710 SDR 11 gas pipeline and concomitant safety equipment along the 8.8-mile alignment. On August 18, 2020, the Tulare County Board of Supervisors approved an indemnification agreement to allow some segments of the underground pipeline to utilize County rights-of-way within easements along or across public roadways. All of Tulare County will benefit as the Project would recover manure methane at dairies and using the methane as a renewable source of natural gas thereby reducing greenhouse gas emissions.

---

## Contact Information

**Name**
Hector Guerra

**Agency Name**
Tulare County Resource Management Agency

**Contact Types**
Lead/Public Agency

**Address**

5961 South Mooney Blvd
Visalia, CA 93277

**Phone**
(559) 624-7000

**Email**
hguerra@co.tulare.ca.us

**Name**

**Agency Name**
CalBioGas South Tulare LLC

**Contact Types**
Project Applicant

## Location

**Counties**
Tulare

**Township**
21,20S

**Range**
24,25E

**Section**
multi

**Other Location Info**
Section Various, Township 21 and 20 S, Range 24 and 25 E of the Lake View School, Tipton, Tulare, and Cairn's Corner USGS 7 ½ minute quadrangles

## Notice of Exemption

**Exempt Status**
Categorical Exemption

**Type, Section or Code**
Sec. 15301, Class 1, and Sec. 15303, Class 3

**Reasons for Exemption**
The Project will not involve any new developments or changes to existing land uses, nor are any proposed, there will be no additional vehicular trips generated as a result of the proposed Activity/Project. The Activity/Project will result in no adverse impact to the environment including aesthetics, air quality, agriculture, biology, cultural, greenhouse gases, hazards/hazardous materials, land use/planning, noise, public services, traffic, or utilities/service systems. Furthermore, the proposed Project site will be required to comply with applicable San Joaquin Valley Unified Air District rules and regulations, including but not limited to, Rule 2010 (Permits Required), Rule 2201 (New and Modified Stationary Source Review), and Rule

9510 (indirect Source Review). The Activity/Project will result in reduction of methane-related GHG by using methane gas emissions from the dairies as an alternative/renewable fuel source, is consistent with draft Tulare County Dairy Climate Action Plan (which incorporates strategies to promote the use of renewable energy sources, including digesters for energy-production), and is also consistent with and implements the California Environmental Protection Agency Air Resources Board's Short-Lived Climate Pollutant Reduction Strategy March 2017; Methane Emissions Reductions from Dairy Manure. As the equipment modification will occur at an existing site and pipelines for this Activity/Project will remain within County of Tulare Rights-of-Way, this action is consistent with 14 Cal. Code Regs. Section 15301 (b) Existing facilities or both investor and public owned utilities used to provide electric power, natural gas, sewerage, or other public utility services and; 14 Cal. Code Regs. Section 15303(d) Water main, sewage, electrical gas, and other utility extensions, including street improvements, or reasonable length to serve such construction. Therefore, the use of CEQA Guidelines Sections 1530l (b) and 15303 (d), as noted above, are applicable and appropriate for this Activity/Project.

## Attachments

**Notice of Exemption**

NOE_S Tulare Biogas Gathering Line_ocr PDF 464 K

# ATTACHMENT Y

# SB 535 Disadvantaged Communities



## California Climate Investments to Benefit Disadvantaged Communities

Disadvantaged communities in California are specifically targeted for investment of proceeds from the state's Cap-and-Trade Program. These investments are aimed at improving public health, quality of life and economic opportunity in California's most burdened communities, and at the same time, reducing pollution that causes climate change. The investments are authorized by the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Nunez, 2016).

In 2012, Senate Bill (SB) 535 (De León, Chapter 830, Statutes of 2012) established initial requirements for minimum funding levels to "Disadvantaged Communities" (DACs). The legislation also gives CalEPA the responsibility for identifying those communities, stating that CalEPA's designation of disadvantaged communities must be based on "geographic, socioeconomic, public health, and environmental hazard criteria".

In 2016, Assembly Bill (AB) 1550 (Gomez, Chapter 369, Statutes of 2016) directed CalEPA to identify DACs and also established the currently applicable minimum funding levels:

- At least 25 percent of funds must be allocated toward DACs
- At least 5 percent must be allocated toward projects within low-income communities or benefiting low-income households
- At least 5 percent must be allocated toward projects within and benefiting low-income communities, or low-income households, that are outside of a CalEPA-defined DAC but within ½ mile of a disadvantaged community.

## Final Designation of Disadvantaged Communities (May 2022)

English | En Español

After receiving public input at workshops and in written comments, in May 2022, CalEPA released its updated designation of disadvantages communities for the purpose of SB 535. In this designation, CalEPA formally designated four categories of geographic areas as disadvantaged:

1. Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts).
2. Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts).
3. Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (307 tracts).
4. Lands under the control of federally recognized Tribes. For purposes of this designation, a Tribe may establish that a particular area of land is under its control even if not represented as such on CalEPA's DAC map and therefore should be considered a DAC by requesting a

consultation with the CalEPA Deputy Secretary for Environmental Justice, Tribal Affairs and Border Relations at TribalAffairs@calepa.ca.gov.

The designation takes into account the latest and best available data and considers factors related to data unavailability. This designation will go into effect on July 1, 2022, at which point programs funded through California Climate Investments will use the designation in making funding decisions.

## Disadvantaged Communities Map

Click to open this map in a new window

CalEPA California Environmental Protection Agency SB 535 Disadva CalEPA... CalEnv... A...

State's Cap-and-Trade Program specifically targeted for investment in disadvantaged communities in California. These funds must be used for programs that further reduce emissions of greenhouse gases.

Senate Bill 535 (De León, Statutes of 2012) directed that at least a quarter of the proceeds go to projects that provide a benefit to disadvantaged communities and at least 10 percent of the funds go to projects located within those communities. The legislation gives CalEPA the responsibility for identifying those communities.

**How to use this map**

- Use your mouse or touchpad to pan around.
- Zoom in/out with a mouse wheel or the +/- icons.
- Search by location or census tract number with the **search icon**.
- Click on a census tract to view additional information in the pop-up window.
- Dock the pop-up window to the side of the screen by clicking the **dock** icon.
- Export a map view that includes the legend and popup using the **screenshot** widget.
- Click the links in the header to view additional resources related to SB 535 Disadvantaged Communities.

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**SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)**

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## Download SB 535 CalEnviroScreen Data

In addition to the interactive map above, SB 535 disadvantaged communities data is available for download in other formats:

- SB 535 Excel Spreadsheet and data dictionary (May 2022). There are two files in this zipped folder. 1) a spreadsheet showing the list of census tracts identified as disadvantaged communities, a list of the Federally recognized tribal areas identified as disadvantaged communities, and the raw data and calculated percentiles for individual indicators and combined CalEnviroScreen scores for census tracts identified as disadvantaged communities. 2) a pdf document including the data dictionary.
- SB 535 ArcGIS Geodatabase (May 2022): A zipped file which can be unzipped, then opened using ArcGIS software to view the results. (ArcGIS is a paid subscription)

Service URL: ArcGIS feature service:
https://services1.arcgis.com/PCHfdHz4GlDNAhBb/arcgis/rest/services/SB_535_

Additional information as well as the previous identification of disadvantaged communities from 2017 using CalEnviroScreen 3.0 is available on the CalEPA page.

For questions, please contact CalEnviroScreen@oehha.ca.gov or (916) 324-7572.

## Documents

- SB 535 List of Disadvantaged Communities (2022) Spreadsheet and Data Dictionary
- SB 535 List of Disadvantaged Communities (2022) Geodatabase

Cal EPA

- Air Resources Board
- Cal Recycle
- Department of Pesticide Regulation
- Department of Toxic Substances Control
- State Water Resources Control Board

Alerts

- Amber Alert
- Cal Alerts
- My Hazards

About

- Governor
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- Register to Vote
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Secretary for Environmental Protection
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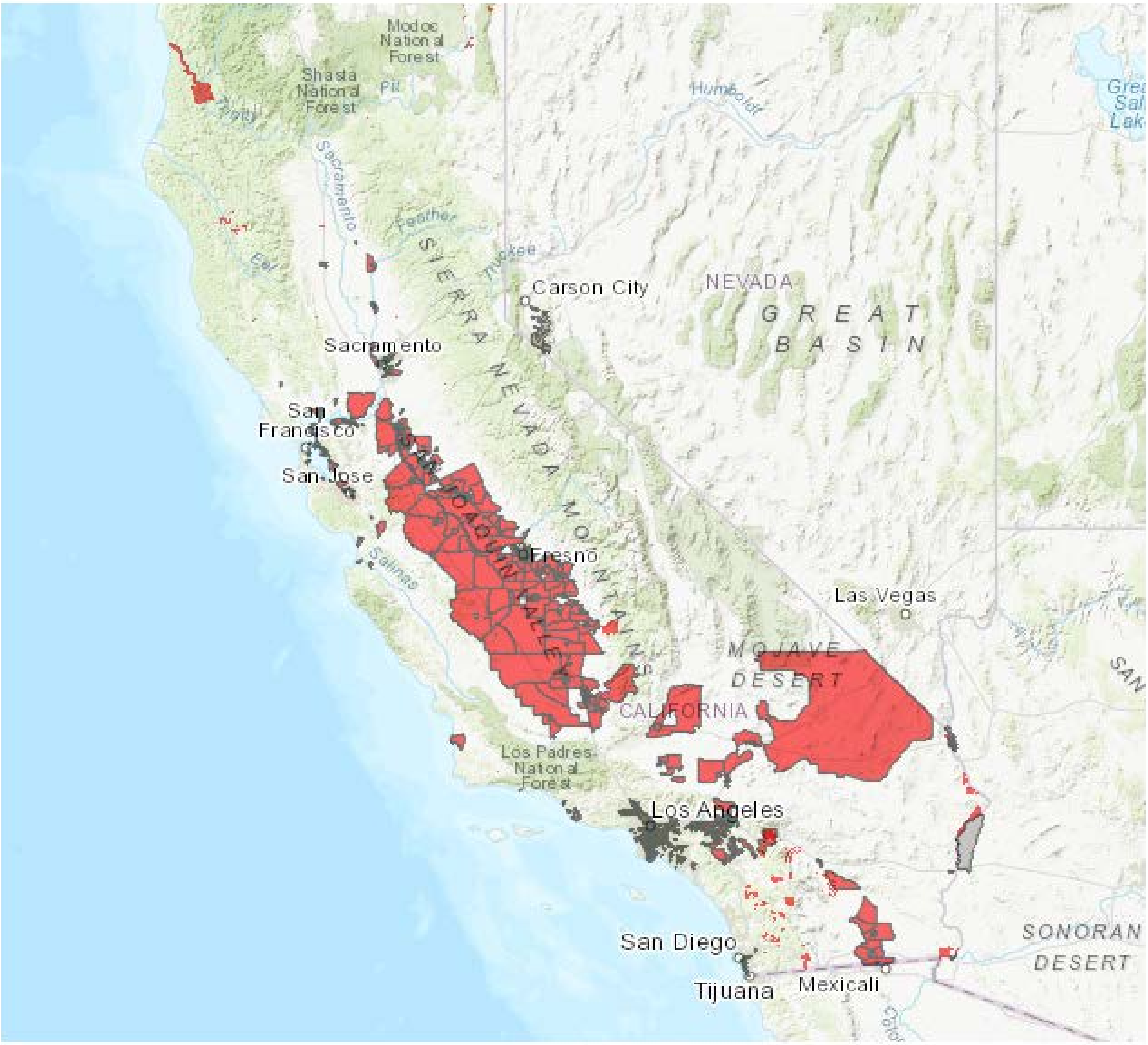
Site Map

# SB 535 Map




SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)

# ATTACHMENT Z

# Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target

Final

March 2022

CALIFORNIA AIR RESOURCES BOARD

# Table of Contents

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# Executive Summary

California took a major step toward reducing greenhouse gas (GHG) emissions and combatting climate change when the Legislature enacted Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), which requires the State to reduce GHG emissions to 1990 levels by 2020. California achieved this target in 2016, four years earlier than mandated. To achieve deeper reductions, the Legislature enacted Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to further reduce GHG emissions to 40 percent below 1990 levels by 2030. In the same year, the Legislature enacted SB 1383 (Lara, Chapter 395, Statutes of 2016), which recognizes the immediate climate benefits of reducing short-lived climate pollutants (SLCP). In the 2017 Scoping Plan Update, the plan for achieving GHGs reductions in the State, the California Air Resources Board) CARB describes that short lived climate pollutant (SLCP) reductions account for about one-third of the cumulative GHG emissions reductions the State is relying on to achieve the statewide 2030 GHG emissions target established under SB 32.

Short-lived climate pollutants, including methane, are powerful climate forcers that have a relatively short atmospheric lifetime, but a high global warming potential compared to other GHGs such as carbon dioxide. SB 1383 establishes SLCP reduction targets and requires CARB to implement a Short-Lived Climate Pollutant Reduction Strategy (Strategy) to achieve these targets. The law sets a 2030 methane emissions reductions target for the dairy and livestock sector (2030 target), which produces more than half of the State's methane emissions. This target is a reduction of 40 percent below 2013 levels, or a reduction of 9 million metric tons carbon dioxide equivalent ($MMTCO_2e$)[1] by 2030. SB 1383 also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to analyze the progress that the sector has made toward achieving the 2030 reduction target and achieving the goals identified in the SLCP Strategy, including progress made in overcoming technical and market barriers to implementing methane emissions reductions measures identified in the Strategy. This Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (Analysis) is responsive to that mandate.

Dairy and livestock methane emissions originate from two primary sources, manure management and enteric fermentation. Manure methane emissions can be reduced through two primary methods—installation of an anaerobic digester and alternative

[1] This emissions reduction estimate is calculated using the 100-year global warming potential (GWP) for methane (IPCC, 2007: Climate Change 2007: Synthesis Report; Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]; IPCC, Geneva, Switzerland, 104 pp (AR4)). The Short-Lived Climate Pollutant Reduction Strategy estimated emissions using the 20-year GWP (AR4).

manure management practices. Anaerobic digesters capture methane-rich biogas for beneficial uses, including in electricity generation and fossil natural gas displacement. Alternative manure management practices reduce manure methane emissions in ways that do not involve an anaerobic digester. Examples include solid separation, conversion to dry scrape, and pasture-based management. Both digester and alternative manure management practices reduce GHG emissions and can improve water quality and nutrient management. Enteric methane emissions can be reduced through genetic selection, diet modification, and feed additives.

This Analysis shows that the dairy and livestock sector is projected to achieve just over half of the annual methane emissions reductions necessary to achieve the target by 2030 through modifications to manure management systems—primarily using anaerobic digesters—and additional reductions through decreases in animal populations. Figure ES-1 shows significant emissions reductions through 2030 absent additional funding after fiscal year 2019-20.[2]

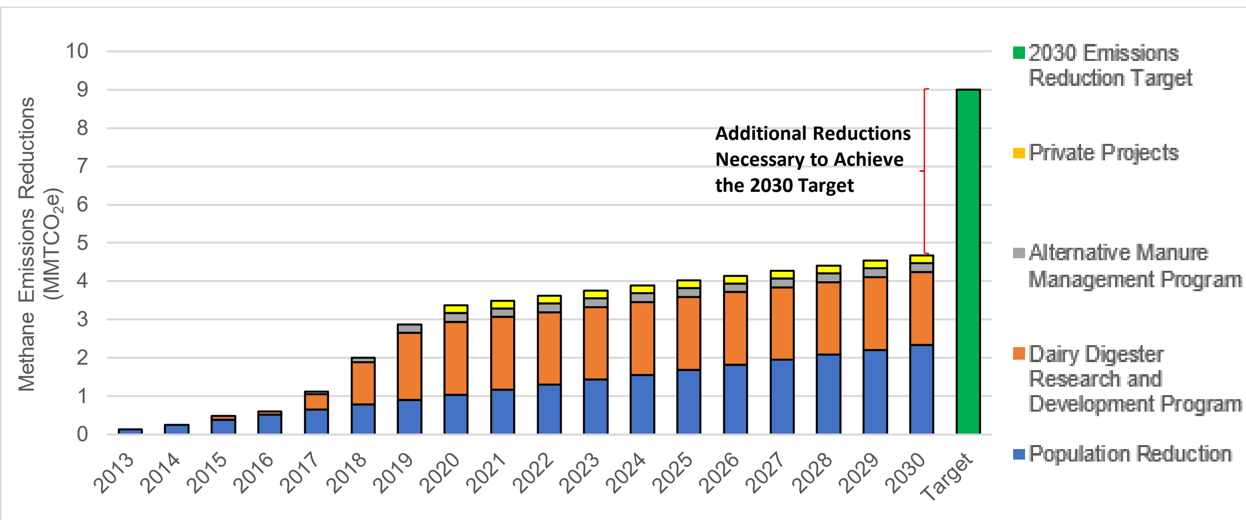


Figure ES-1. Projected Annual Methane Emissions Reductions through 2030 without Additional Funding beyond FY 2020-21

To meet the 2030 target, the dairy and livestock sector will need to achieve considerable emissions reductions from additional manure management projects, proven enteric mitigation strategies, or a combination of both over the next few years.

To understand what level of resources are needed to achieve the target, CARB staff looked at existing dairy methane emissions reduction efforts, including both grant

[2] This does not include $32 million in FY 2021-22 appropriations because it is uncertain how these appropriations will be allocated.

programs that fund the initial capital costs and market-based programs that incentivize GHG emissions reductions or low carbon fuel production.

Over the past six years, California Climate Investments (CCI)—the program that utilizes the State's Cap-and-Trade Program auction proceeds to facilitate GHG emissions reductions—has offset some capital costs through two CDFA grant programs to reduce manure methane emissions: the Dairy Digester Research and Development Program and the Alternative Manure Management Program. An approximate appropriation of $289 million in CCI funds has facilitated the construction of 233 dairy and livestock GHG emissions reduction projects. Many of these manure methane reduction projects are also generating environmental credits through CARB's Cap-and-Trade Program, Low Carbon Fuel Standard (LCFS) Program, and the federal Renewable Fuel Standard (RFS) Program. These projects, cumulatively funded through FY 2019-20, are expected to deliver the 2.0 $MMTCO_2e$ in annual methane emissions reductions noted above from manure management systems by 2030, or about 22 percent of the reductions necessary to achieve the 2030 target.

New or expanded local, State, or federal incentives or funding mechanisms could potentially accelerate the capture and beneficial use of California biomethane, provide additional revenue necessary to ensure that California's dairy manure methane emissions are captured, and direct the biogas to difficult-to-decarbonize sectors. Replacing fossil natural gas with upgraded dairy biogas (biomethane) or other alternatives is important for California's near and longer-term climate goals, but the cost to procure biomethane can be six to ten times more expensive than fossil natural gas. This cost disparity is almost entirely associated with the cost of bringing biomethane to market and will likely persist into the future. This is one of the primary reasons incentives are needed for California's dairy and livestock sector to adopt methane reduction strategies that also support the transition away from fossil natural gas supplies. Additional funding could also accelerate the adoption of alternative manure management projects. These projects provide climate benefits through avoided methane production and environmental co-benefits including water quality improvements and conservation, reduction of synthetic fertilizer usage and improvement of nutrient management, as well as groundwater protection.

Through coordinated State, industry, and utility efforts, the dairy and livestock sector has made meaningful progress in overcoming technical barriers to digester projects, interconnecting to utility electrical grids and pipeline networks, and meeting biomethane pipeline injection standards. Improved environmental credit certainty has also reduced the most considerable market barriers to digester projects by helping project developers obtain funding and financing. Challenging sector economics, insufficient availability of public funds, and underdeveloped markets for value-added manure products are persistent market barriers for both digester and alternative manure management projects. There has been limited progress in overcoming technical barriers to alternative manure management practices because emissions reductions vary based on site-specific factors. There has also been limited progress in overcoming both technical and market barriers to enteric reductions. Enteric methane-reducing feed additives may achieve considerable near-term emissions reductions. There are two commercially available products that were developed for enteric methane mitigation, with potential emissions reductions up to 10-20 percent. Additional feed additives are under development that may provide larger enteric methane emissions reductions.

Despite progress in overcoming barriers, there is more to do to ensure that the State meets the 2030 target. Remaining barriers may be overcome through multiple reasonable efforts, including allocation of additional local, State, or federal funding or incentives. If the remaining reductions needed to achieve the 2030 target are met through a mix of California dairy projects in which half are dairy digesters and half are alternative manure management projects, then at least 420 additional projects may be necessary. This approach would cost an amount between $0.8 and $3.7 billion, which could be supported by local, State, and federal funding, or other financial mechanisms, such as the pilot financial mechanism outlined in SB 1383.[3] If, going forward, only digester projects were developed to achieve the target, approximately 230 additional digesters may be needed, at a cost between $0.7 and $3.9 billion depending on the types of technologies selected. For example, prioritizing deploying digesters with internal combustion engines is the lowest-cost option ($0.7 billion) to achieve the 2030 target, but this would result in on-site criteria pollutant emissions. Alternatively, deployment of digesters that utilize fuel cell technology may avoid these emissions, but at a significantly higher cost ($3.9 billion). Finding 1-6 of this Analysis describes project types, technologies, and cost ranges. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

[3] On February 24, 2022, the California Public Utilities Commission approved Decision 22-02-025 adopting biomethane procurement standards pursuant to SB 1440 (Hueso, Chapter 739, Statutes of 2018), including procurement of biomethane from the California dairy and livestock sector.

Regardless of the project and technology mix used, the most important factors for achieving the 2030 target are ongoing capital funding for new methane emissions reduction projects, continued revenue streams that incentivize dairy biogas capture and beneficial use, and an available and accepted means of reducing enteric methane emissions. Even with considerable progress toward achieving the target since the enactment of SB 1383, the statute requires CARB to adopt a regulation to meet the target, provided that certain conditions are met. Further, CARB is only authorized to implement regulations to meet the 2030 target after January 1, 2024, provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs. In designing a regulation for methane emission reductions, CARB staff will consider reasonable strategies to support the sector in meeting the 2030 target, which may include strategies that further support biogas capture and end-uses needed to advance the State's carbon neutrality efforts.

While the California dairy and livestock sector has made significant progress, it must still achieve considerable methane emissions reductions to meet the 2030 target. This will require implementation of additional methane emissions reductions strategies, and continued collaboration among agencies and other stakeholders. In addition, CDFA plans to convene a working group to address market development barriers for facilitate value-added manure products. CARB will continue to track progress of methane emission reductions project funding and outcomes, manure management and enteric methane reduction options, and will evaluate progress in the 2022 Scoping Plan Update.

# Introduction

California has long championed environmental protection, and the State has made significant investments and efforts to decarbonize its economy. In 2006, the Legislature passed and the Governor signed the California Global Warming Solutions Act. Assembly Bill (AB) 32 (Núñez, Chapter 488, Statutes of 2006) requires the State to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It also tasked the California Air Resources Board (CARB or Board) with developing a climate change scoping plan that details how the State will achieve its climate target and requires CARB to periodically update the plan. The Board adopted the first Climate Change Scoping Plan in December 2008 and updated this plan in 2013 and 2017.

Through aggressive pursuit of regulatory and voluntary GHG emissions reduction measures across economic sectors, California GHG emissions fell below 1990 levels in 2016, 2017, 2018, and 2019. Acknowledging the need to make deeper GHG emissions reductions to help slow climate change, the Legislature passed Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to reduce GHG emissions to 40 percent below 1990 levels by 2030. Figure 1 shows these GHG emissions reduction targets as well as the State's additional goal to reduce GHG emissions by 80 percent below 1990 levels by 2050.[4] Meeting these emissions reduction targets will be critical as California strives to achieve another goal – reaching carbon neutrality by 2045.[5] The Intergovernmental Panel on Climate Change (IPCC) has acknowledged carbon neutrality as necessary to limit global warming to 1.5 degree Celsius or less, the goal set by the international Paris Agreement on climate.

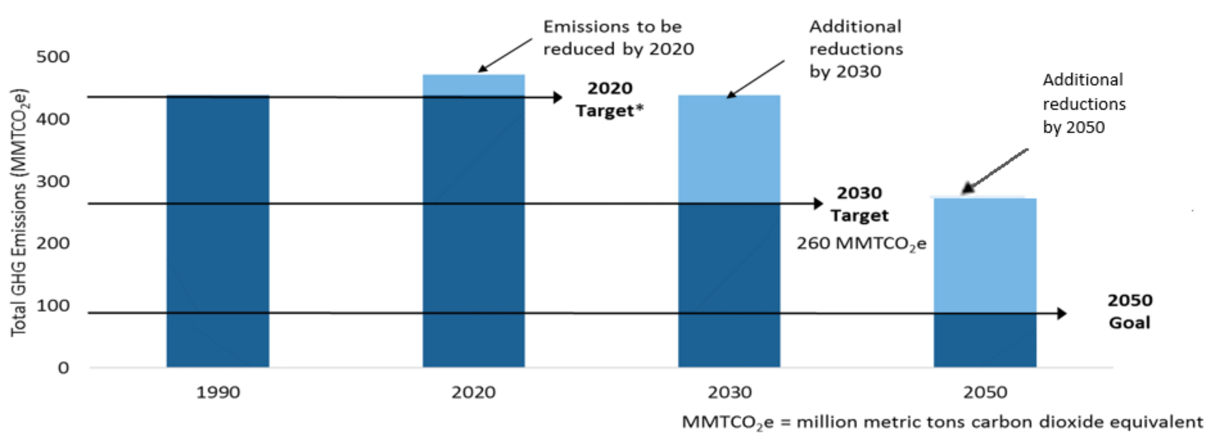


Figure 1. California GHG Emissions Reduction Targets and Goal through 2050

[4] Executive Order S-3-05.
[5] Executive Order B-55-18.

The Legislature also took action to limit emissions of short-lived climate pollutants (SLCP), which are powerful climate forcers that have relatively short atmospheric lifetimes but high global warming potentials (GWP). As a result, SLCP emissions reductions achieved now can have an immediate beneficial impact on climate change. Methane, a powerful SLCP, stays in the atmosphere for approximately a decade before being converted to carbon dioxide.[6] The effect of methane on climate change is 25 times stronger than that of carbon dioxide using the 100-year GWP (GWP 100), and 75 times stronger than carbon dioxide using the 20-year GWP (GWP 20).

CARB uses GWP 100 to quantify statewide methane emissions for inventory and regulatory purposes. GWP 100 is the standard for inventory development and aligns with IPCC and US Environmental Protection Agency (EPA) methods, allowing for comparison of the state inventory with other sub-national and international inventories through common methodologies and requirements for accuracy.

In 2014, the Legislature passed SB 605 (Lara, Chapter 523, Statutes of 2014), which requires CARB to develop a strategy to reduce SLCP emissions in the State. In response, staff developed and the Board approved a comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy). In 2016, the Legislature passed SB 1383 (Lara, Chapter 395, Statutes of 2016), which requires CARB to approve and begin implementing the Strategy, and establishes a requirement, among others, for different SLCPs[7] to meet methane emissions reduction targets. More specifically, SB 1383 requires the California dairy and livestock sector to reduce methane emissions from enteric fermentation and manure management to 40 percent below 2013 levels by 2030. It also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to adopt regulations to achieve this mandate if certain conditions are met. Specifically, SB 1383 intends to prioritize the use of voluntary and incentive-based measures to achieve those reductions before regulations are implemented. To achieve that end, the law calls for several specific efforts to incentivize reductions, including requiring CARB to work with stakeholders to identify and address technical, market, regulatory, and other challenges and barriers to development of dairy methane emissions reduction projects. Further, CARB is only

[6] While methane itself is not considered a toxic air contaminant, it is a large component of biogas, which may contain a mixture of gases including some toxic air contaminants like hydrogen sulfide. Removing these toxic air contaminants can reduce potential health impacts associated with the processing, transportation, and use of biogas streams.

[7] SB 1383 requires the reduction in the statewide emissions of methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030. Additionally, the bill requires a 50 percent and 75 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and 2025, respectively. SB 1383 also sets a goal that not less than 20 percent of edible food that is currently disposed of is recovered for human consumption by 2025.

authorized to implement the regulations to meet the 2030 target after January 1, 2024, provided that CARB and CDFA determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs.

The Strategy put forward a path to achieve the SLCP emissions reduction goals established in SB 1383 in a way that provides both environmental and economic benefits to the State. Using the latest scientific and emissions information on SLCPs, it outlines the emissions reduction progress for specific SLCPs, potential options for additional reductions of these SLCPs, and strategies to achieve the respective emissions reduction targets. SLCP reductions are necessary to achieve the State's 2030 GHG emissions target, as described in the 2017 Scoping Plan Update, as well as the mid-century carbon neutrality goal. Notably, while some State programs incentivize dairy and livestock methane emissions reductions, no existing California programs directly require them or incentivize a sector-wide implementation of reduction measures. For example, CARB's Low Carbon Fuel Standard (LCFS) program provides some incentive for dairy operations to develop digesters and receive credits for biomethane production. However, on its own this program does not require operators to develop projects and through its credit system may not support statewide implementation of anaerobic digesters at dairies, and thus these emissions will not decrease without additional targeted programs or other interventions. In contrast, for the electricity and transportation sectors, the Cap-and-Trade Program acts as a backstop to ensure that GHG emissions reductions are achieved.

The Strategy describes a variety of manure management options that can provide the greatest methane emissions reduction potential, recognizing that not every option is feasible for each facility. The Strategy also recommends additional research to evaluate potential enteric methane emissions reduction options as well as the acceleration of early project development through incentives and market development. Prior to implementing regulations, incentives like California Climate Investments (CCI) allocations using Cap-and-Trade Program auction proceeds will encourage voluntary methane emissions reductions at dairies. The Strategy recognizes that implementing a variety of mitigation measures is necessary to achieve the 2030 target and will deliver significant reductions from the dairy and livestock sector while providing a variety of environmental and economic benefits.

Upon adoption of the Strategy and in compliance with SB 1383, CARB convened an interagency Dairy and Livestock Greenhouse Gas Emissions Working Group (Working Group) consisting of CARB, CDFA, California Energy Commission (CEC), and California

Public Utilities Commission (CPUC) principals. At the initial meeting in May of 2017, the Working Group convened three stakeholder subgroups composed of representatives and subject matter experts from State agencies, industry, academia, and the environmental justice community. The objective of these subgroups was to comply with SB 1383's requirement for CARB to work with stakeholders to identify and address barriers to dairy and livestock methane emissions reductions projects, and to develop actionable recommendations that State agencies could implement to help overcome these barriers.

Subgroup 1 provided recommendations to the Working Group to overcome barriers to non-digester manure management practices that focused on available and potential incentives, and developing value-added manure product markets. Subgroup 2 provided recommendations to the Working Group to overcome barriers to implementing livestock digester projects in California, along with a dairy digester emissions matrix that shows potential GHG and criteria pollutant emissions from dairy biogas use. Subgroup 3 focused on research needs related to dairy and livestock methane emissions reductions including enteric fermentation, and published a comprehensive Dairy Research Prospectus to Achieve California's SB 1383 Climate Goals, which outlines research concepts and needs to guide future funding of research projects in California. Over 18 months, the subgroups developed a set of Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group and presented them to the Working Group in December 2018. These recommendations outline potential solutions to overcome barriers to methane emissions reduction projects at California dairy and livestock operations and highlight innovative research on methane emissions reductions.

SB 1383 includes additional requirements on CARB to help provide market and environmental credit certainty to biogas-capturing anaerobic digester projects. These requirements, which CARB staff have fulfilled, include developing a white paper describing a potential pilot financial mechanism that, if implemented, could improve market stability for environmental credits from dairy digester projects. CARB, CDFA, and CPUC collaborated in selecting six dairy biomethane pipeline injection pilot projects to receive rate-recoverable infrastructure funding. Evaluating the factors that affect the cost and technical feasibility of these projects will help the State better understand and refine future incentives and regulatory measures. CARB staff also developed a frequently asked questions document discussing the potential impact that a dairy and livestock methane emissions reduction regulation would have on environmental credits generated under the LCFS Program and Cap-and-Trade Program.

Finally, SB 1383 requires CARB, in consultation CDFA, to analyze the progress that the sector has made toward achieving the 2030 target. This Analysis discusses the expected methane emissions reductions through 2022 and the estimated number of additional projects necessary to achieve the 2030 target. It also explores progress made in overcoming the technical and market barriers to implementing dairy and livestock methane emissions reductions projects.

## Dairy and Livestock Sector Methane Emissions

In 2013, methane accounted for 40 million metric tons carbon dioxide equivalent ($MMTCO_2e$),[8] or approximately nine percent[9] of the State's GHG emissions (Figure 2). The dairy and livestock sector has been and continues to be the largest source of methane emissions in California, producing approximately 22 $MMTCO_2e$, or about 55 percent, of statewide methane emissions (Figure 3). Eighty percent of these emissions are from manure management and enteric fermentation at more than 1,300 dairies throughout the State. These dairies house more than 1.7 million milking cows and a similar number of replacement stock.[10]

Methane emissions at dairy and livestock operations come from two main sources—the animals themselves through enteric fermentation and manure management operations, especially at dairies. Enteric and manure emissions are both functions of cattle population, meaning that that more head of cattle there are, the higher the methane emissions. As a result, market dynamics such as changes in cost, revenue, or product demand can lead to fluctuations in methane emissions.

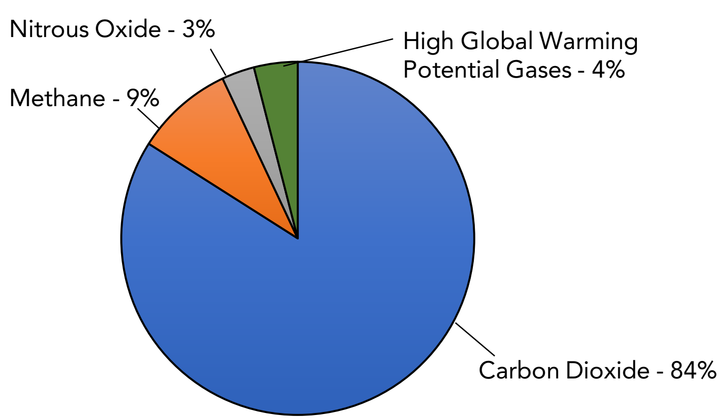


Figure 2. 2013 California GHG Emissions by Gas (Total 2013 Emissions~460 $MMTCO_2e$)

[8] 100-year GWP from IPCC AR4.
[9] California Greenhouse Gas Emissions for 2000 to 2017.
[10] California Agricultural Statistics Review 2018 to 2019.

The dairy and livestock sector has the potential to achieve significant methane emissions reduction from manure management operations at relatively low cost compared to other CCI-funded programs. Projects average \$29 and \$70 per $MMTCO_2e$ including both public and private funding for dairy digester and alternative manure management projects, respectively.[11,12] Enteric methane mitigation strategies also have important methane mitigation potential, but there is limited cost information available since only a few products are scientifically proven and commercially available.

Enteric fermentation is a natural digestive process that occurs within the digestive tract of ruminant animals such as cattle, sheep, and goats. In 2013, enteric fermentation emissions represented about 30 percent of California's total methane emissions (Figure 3), with two-thirds from dairy cows and the remaining one-third from other animal types. During the digestive process, microbes in the rumen decompose and ferment plant matter, which produces methane that ruminants subsequently emit, mostly through eructation (burping). A variety of factors influence enteric fermentation emissions including breed, diet, and the presence of feed additives, with the latter offering significant potential methane emissions reductions. In general, methane emissions from enteric fermentation can potentially be reduced through selective breeding, dietary modifications that improve milk production efficiency, and the introduction of methane-reducing feed additives.

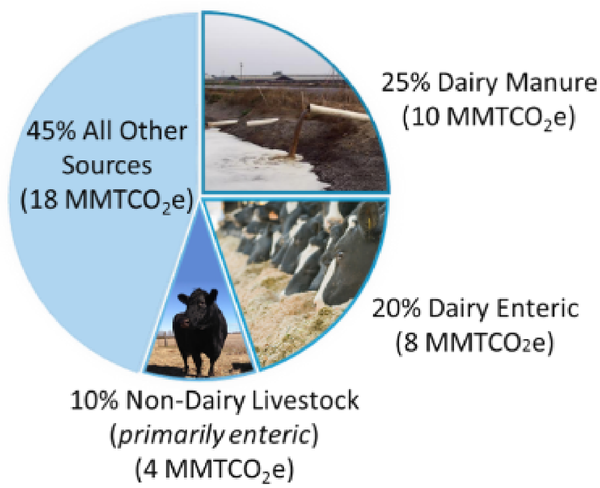


Figure 3. 2013 California Methane Emissions by Source

Anaerobic manure management and storage comprise the other main source of methane emissions at California dairy and livestock operations, accounting for about 25 percent of California's total methane emissions. Manure management systems that

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[11] Dairy Digester Research and Development Report of Funded Project from 2015 to 2019.
[12] Alternative Manure Management Program Webpage.

treat or store manure under anaerobic conditions (i.e., those common to liquid manure management lagoons) are a large source of methane emissions. Anoxic manure treatment and storage conditions, common in manure settling basins and storage lagoons, are conducive to methanogenic bacteria producing methane from volatile solids. Methane emissions from anaerobic manure management can be mitigated through capture and destruction, or through avoidance of production.

Two types of projects—dairy digesters and alternative manure management projects—effectively reduce a significant amount of methane emissions from dairy and livestock operations. Dairy digesters involve installation of an anaerobic digester to capture biomethane produced from dairy waste for beneficial end-uses including but not limited to onsite electricity generation to offset facility needs, or delivery to the electrical grid. Upgraded biomethane that meets utility pipeline specifications set by the California Public Utilities Commission (CPUC) can also be injected into the natural gas pipeline network to offset use of fossil natural gas in multiple sectors. Use of upgraded biomethane in vehicles in place of diesel also provides the additional co-benefit of reducing nitrogen oxides (NOx) emissions. Dairy biomethane can also be used as a heat source in industrial application, or as a feedstock for low carbon fuels including renewable hydrogen and dimethyl ether. The biomethane produced is eligible for credits in CARB's LCFS program, the Federal Renewable Fuels Standard, or CARB's Cap-and-Trade offsets program, which act as an ongoing revenue stream for facilities to help offset the initial high capital costs of development as well as support the ongoing operational costs of the digester.

Alternative manure management practices reduce the amount of manure (and volatile manure solids) managed or stored under anaerobic conditions; the goal of these practices is to limit methane production and emissions. Examples of effective alternative manure management practices include conversion to "solid," "dry," or "scrape" manure management; installation of a compost-bedded pack barn; increase in the time animals spend on pasture; or implementation of solid-liquid separation technology into flush manure management systems (e.g., various types of mechanical separators and weeping walls). Other alternative manure management strategies that may result in methane emissions reductions include but are not limited to acidification, which involves the application of acid(s) to animal manure to reduce emissions; vermifiltration, which is an aerobic decomposition process that produces worm castings; and chemical flocculation, which involves using polymers to increase the solid separation rate from animal manure streams. A more detailed overview of these and other alternative manure management practices is available in the Newtrient technology catalog—a source of information on manure management practices that can reduce environmental impacts.[13]

These practices can also provide important environmental co-benefits including improved water quality and nutrient management, and more easily exportable manure solids. For example, dairies can contribute to groundwater pollution through nitrate and salt leaching when overapplying manure to cropland, however, these components may replace synthetic fertilizer or improve soil health in other regions. Exporting excess nutrients and solids may also help dairy and livestock operations comply with water quality requirements. In California, dairy manure is largely managed in liquid form, making it difficult and cost-prohibitive to export without solid-liquid separation. Certain alternative manure management practices can remove manure solids, nitrogen, and salt from the manure stream and concentrate them in the solids that can be more readily exported as organic fertilizer or converted them into environmentally benign end products such as nitrogen gas. Manure solids may be further processed into value-added manure products like compost or soil amendments that can provide additional revenue, though market development remains a barrier. Alternative manure management strategies also provide flexibility to operations seeking to reduce methane emissions where a digester may be infeasible.

Through the strategies described above, the dairy and livestock sector can make considerable progress toward achieving the target of reducing methane emissions to 40 percent below 2013 levels by 2030. This Analysis describes progress the sector has already made toward achieving the target through manure methane emissions reduction projects. It also assesses progress that may occur based on various funding scenarios, reductions in animal populations, or commercial availability of a methane-reducing feed additive. Additionally, it discusses technical and market barriers to methane emissions reductions strategies that must be overcome to achieve the 2030 target.

[13] Newtrient provides information about manure management strategies and associated environmental impacts to dairy producers through an online technology catalog. Newtrient participated in CARB's Dairy and Livestock GHG Emissions Workgroup but does not have a formal relationship to CARB. Reference to that material does not constitute an endorsement of that catalog, or any associated strategies, technologies, etc., included therein.

# Analysis and Findings

## Analysis Item 1: California's Dairy and Livestock Methane Emissions Reduction Progress and Projected Annual Emissions Reductions through 2030

### Finding 1-1: The Sector Has Made Significant Progress, But Will Not Meet the 2030 Target without Almost a Doubling of Emissions Reductions Projects

The California dairy and livestock sector has predominantly relied on manure management strategies to achieve the methane emissions reductions directed by the Legislature. Even with limited enteric methane mitigation options, the sector is on course to achieve significant emissions reductions. Through private investments and public incentive funding programs, approximately 278 manure methane emissions reduction projects have been completed or are under construction at California's dairy farms. Of these, CCI funded 233 projects through CDFA's Dairy Digester Research and Development Program (DDRDP) and Alternative Manure Management Program (AMMP), which have been instrumental in driving manure methane emissions reduction projects at California dairy operations. DDRDP provides up to half of the capital cost of construction, and AMMP encourages private matching funds. Both programs are consistently over-subscribed, with requested funds usually about twice the amount available.

As of December 2020, 22 DDRDP and 61 AMMP projects were complete and operational. An additional 96 DDRDP and 54 AMMP projects are under construction, with expected completion by the end of 2022. The latest round of CCI funding in fiscal year (FY) 2019-20 funded 12 DDRDP and 13 AMMP projects; all are expected to be operational by the end of 2022. Aggregating the emissions reductions expected from all 233 CCI projects yields an estimated annual methane emissions reduction of 2.0 $MMTCO_2e$[14] by the end of 2022.[15] The emissions reductions counted toward the 2030 target represent over 20 percent of the 9 $MMTCO_2e$ required to achieve that target. Stated differently, CCI funded dairy and livestock projects are expected to

[14] Emissions reduction estimates are in 100-year GWP (AR4). Estimated emissions reductions using 20-year GWPs can be calculated by multiplying 100-year GWP figures in this Analysis by 2.88.

[15] These estimates do not include the anaerobic digestion projects receiving Aliso Canyon Mitigation Settlement funds, which will result in an estimated additional 0.3 $MMTCO_2e$ in annual methane emissions reductions. Since these projects count toward natural gas sector mitigation, they do not count toward the 2030 target.

reduce total methane emissions from the sector to about 9 percent below 2013 levels by the end of 2022.

CARB, in collaboration with air districts and dairy and livestock industry groups, identified as many as 45 additional manure management projects implemented or under development using only private funding throughout the State since January 1, 2013. Of these, 40 involve installation of a solid-liquid separation system, and the remaining five involve installation of an anaerobic digester. Solid separation systems reduce the amount of volatile solids that are managed anaerobically by diverting a fraction of these solids to a dry management system to produce compost, soil amendment, and bedding, preventing them from producing significant methane emissions. To estimate reductions from these projects, CARB staff used average methane emissions reductions for DDRDP and AMMP projects, respectively. The combined annual methane emissions reductions amount to 0.2 $MMTCO_2e$ from these projects, with 0.1 $MMTCO_2e$ each from digester and alternative manure management projects.

Changes in animal populations are an additional driver of methane emissions reductions, caused by factors including reduced product demand, increased costs, insufficient revenue, greater out-of-State competition, and land use changes. For example, consumer preferences may change, reducing the demand for animal-based products. Increased out-of-State competition and decreased national and international demand may also result in oversupply of products and animal population reductions. Increases in production costs for commodities like animal feed, electricity, and fuel can also have significant impacts on the financial viability of animal operations, especially when coupled with low commodity prices. In other cases, competing land uses like conversion to high-value crops or urban encroachment may lead to facility closures and animal population reductions.

Every five years, the U.S. Department of Agriculture (USDA) conducts a Census of Agriculture (Ag Census), which provides the most consistent and reliable population data available in absence of state-level activity data. As part of the Ag Census, USDA reports the number of animals by type on each farm in the U.S., allowing for state-specific population tracking, including for California's GHG Emission Inventory. USDA's two most recent Ag Census reports, from 2012 and 2017, cover dairy and livestock population changes between 2008 and 2017, and provide a basis for estimating methane emissions reductions from average annual population changes. The 2012 Ag Census also provides a reasonable 2013 baseline because it quantifies dairy and livestock populations in California by animal type as of December 31, 2012. Based on the 2012 and 2017 Ag Census reports, CARB staff calculated an average annual decline of 0.5 percent in animal populations from the sector between 2008 and 2017. Assuming that this population change trend will remain constant, methane emissions reduction attributable to sector population decreases will be ~0.13 $MMTCO_2e$ annually or 1.3 $MMTCO_2e$ total through 2022.

Adding methane emissions reductions expected from State- and privately funded manure management projects with those from expected animal population decreases yields a total methane emissions reduction in 2022 relative to 2013 of ~3.5 $MMTCO_2e$, as shown in

Table 1 below.[16] Assuming that the animal population will continue to decrease at approximately 0.13 $MMTCO_2e$ annually,[17] and not taking into account any additional funding that may be available for manure methane reduction projects beyond FY 2019-20, the total estimated 2030 methane emissions reductions would be approximately 4.6 $MMTCO_2e$. This would be just over half of the 9 $MMTCO_2e$ emissions reductions needed to meet the 2030 target – with about 4.4 $MMTCO_2e$ reductions remaining (Figure 4).

[16] Due to the time required to construct dairy methane emissions reductions projects—especially anaerobic digesters pipeline injecting biomethane (between 18 and 24 months)—a limited number of projects have been completed to date.

[17] Starting in March of 2020, California enacted shelter-in-place orders and temporary closures of public and private gathering spaces due to the global pandemic. Resulting closures of schools and restaurants likely exacerbated dairy sector economic challenges and may have lasting impacts, including accelerated facility closures and decreases in animal population. However, due to uncertainty about net long term impacts the pandemic may have on the dairy and livestock sector, this Analysis assumes that recent trends in animal population trends observed in USDA's 2012 and 2017 Ag Census change will remain consistent through 2030.

Table 1. Estimated California Dairy and Livestock Methane Emissions Reduction by the End of 2022

| Reduction Type | | Number of Projects Funded through FY 2019-20 | Expected Emissions Reductions Through 2022 ($MMTCO_2e$) |
|---|---|---|---|
| Population Change | | Not Applicable | 1.3 |
| Anaerobic Digester | State-funded (DDRDP) | 118 | 1.8 |
| | Privately funded | 5 | 0.1 |
| Alternative Manure Management Practices | State-funded (AMMP) | 115 | 0.2 |
| | Privately funded | 40 | 0.1 |
| **Total** | | **278** | **3.5** |

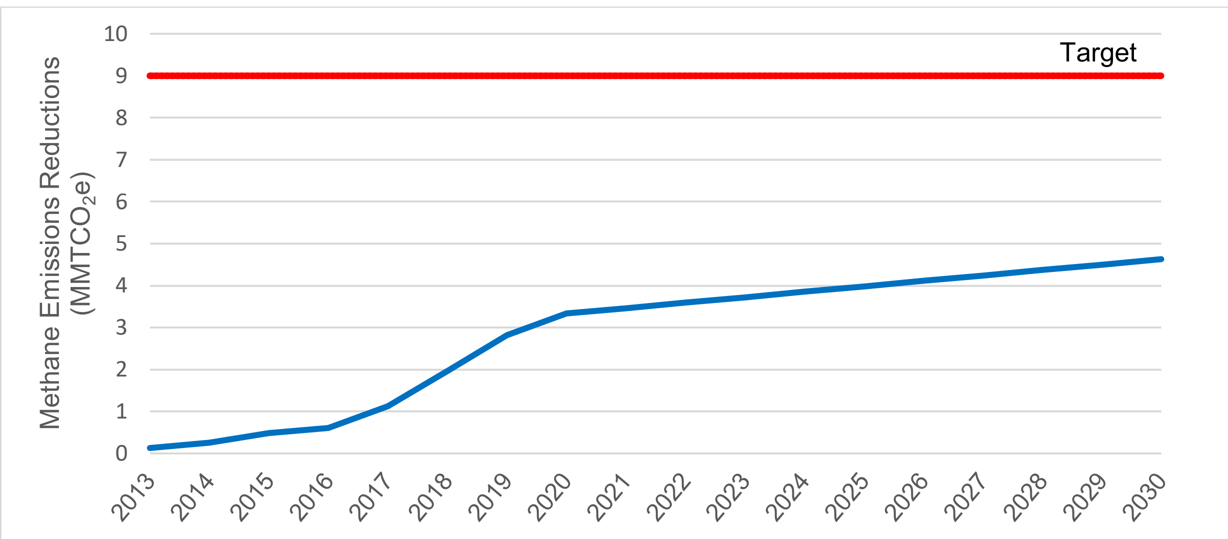


Figure 4. Projected Annual Methane Emissions Reductions through 2030 without Additional CCI Funding beyond FY 2020-21

The remaining 4.4 $MMTCO_2e$ in emissions reductions are expected to be achieved through manure management strategies but may be advanced by widespread adoption of effective enteric methane mitigation strategies. To estimate additional manure methane emissions reductions projects needed to reach the target, CARB staff used average reductions from DDRDP and AMMP projects. Staff calculated average project-level methane emissions reductions by program using figures reported by CDFA through DDRDP and AMMP. Based on the average emissions reductions, staff determined the number of additional projects necessary to achieve the 2030 target. This assumes that distribution of project types will remain roughly equal between digesters and alternative manure management projects, consistent with past practice. Based on this approach, at least 210 anaerobic digestion and 210 alternative manure management projects are necessary to achieve the remaining 4.4 $MMTCO_2e$ in methane emissions reductions. However, future project types may vary dependent upon available incentives and operator preference. If only dairy digester projects were implemented—which are about ten times as effective at reducing emissions than alternative manure management projects—over 230 projects would be necessary to achieve this level of emissions reductions. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

## Finding 1-2: Public and Private Funding Support Methane Emissions Reduction Projects

Significant allocations of CCI funding have enabled the sector to make progress toward the 2030 target. From 2014 through 2020, the Legislature appropriated approximately $289 million in CCI funds for dairy methane emissions reduction projects. These funds, administered through CDFA's DDRDP and AMMP, have been effective in leveraging private capital investment and achieving cost-effective methane emissions reductions. With local, State, and federal funding, the dairy and livestock sector will be able to implement additional projects to help meet the 2030 target. Table 2 (below) shows that dairy methane projects constructed using CCI funds through the DDRDP and AMMP have successfully leveraged over $1.60 in match funding for each CCI dollar invested.[18]

[18] DDRDP eligibility requirements include a mandatory private match contribution of at least 50 percent of initial project cost estimates. AMMP does not require private match contributions.

Table 2. Private Funding Contributions per CCI Dollar Invested

| Funding Sources | Programs | | Total Funding |
|---|---|---|---|
| | AMMP | DDRDP | |
| CCI ($ million) | $67.8 | $195.5 | $263.3 |
| Private Match ($ million) | $9.9 | $413.1 | $423.0 |
| Private Match per CCI Dollar Invested ($) | $0.15 | $2.11 | - |

In addition to DDRDP and AMMP, additional State programs, including the Cap-and-Trade Program, the LCFS Program, CPUC's Bioenergy Market Adjusting Tariff (BioMAT), CPUC's Renewable Gas Pipeline Interconnection Incentive Program and CPUC's SB 1383 Biomethane Pipeline Injection Pilot Project Program, have supported dairy and livestock methane emissions reduction projects through credit generation and grants, and other bioenergy and biofuel incentives. To date, more than $1 billion in combined public and private funding has supported approximately 280 anaerobic digester and alternative manure management projects. Additionally, public funds have supported rate-recoverable programs for biomethane pipeline interconnection infrastructure, which help deliver biomethane to end users.

The Strategy recommended a minimum funding amount[19] of at least $100 million per year for five years as necessary to accelerate significantly project development by offsetting capital costs and economic risks for manure management methane emissions reduction projects. CARB and CDFA, working with industry stakeholders and project developers during public development of the Strategy, estimated that $500 million would greatly increase the deployment rate of manure management projects within the State, though that amount was not estimated to be sufficient to achieve the 2030 target. To date, CDFA's DDRDP has awarded approximately $200 million in CCI funds for 118 dairy digesters, nearly an eightfold increase over the number of digesters operating prior to the availability of CCI funds. Similarly, CDFA's AMMP has awarded approximately $68 million for 115 alternative manure management projects and has greatly accelerated adoption of those practices. CARB staff estimates an additional $600 million in privately matched CCI funds, or similar public incentives, is necessary to achieve the emissions reductions still needed to meet the 2030 target through dairy digester projects. Despite considerable State investment and private match funding, incentives have not been sufficient to achieve

[19] In the Strategy, CDFA estimated that at least $100 million in the form of grants, loans, or other incentives would be needed for five years to support the development of necessary methane emissions reducing manure management projects including digesters and alternative manure management projects, as well as associated infrastructure.

the 2030 target. The FY 2019-20 CCI allocation of $34 million was considerably lower than the $99 million available in FY 2017-18 and FY 2018-19, falling $66 million short of annual funding needs. The proposed FY 2020-21 appropriation of $20 million did not materialize because of State budget cuts. The FY 2021-22 budget includes an appropriation of $32 million for CDFA's livestock methane reduction program, with priority given to AMMP.

CDFA's DDRDP projects have been the primary driver of GHG emissions reductions in the dairy and livestock sector since FY 2014-15. Prior to the availability of CCI funds, about 15 digesters were operating in California—far short of the 799 candidate dairies identified by the USDA AgSTAR program and 543 dairies identified in the Strategy[20] as necessary to achieve the 2030 target.[21] Most of the digesters installed prior to the start of CCI (2006-2013) relied heavily on public funding from CEC's Dairy Power Production Program. Emissions reductions resulting from these projects are not counted towards the target because they were online prior to the 2013 baseline year. Figure 5 below shows the number of digesters in place prior to the baseline year, the number of digesters resulting from CCI funding, and the number of additional digester projects necessary to achieve the 2030 target.

[20] The Strategy was adopted prior to the opening of the Alternative Manure Management Program and assumed that most of the necessary methane emissions reductions would result from digester installations.

[21] Noted in Table 17: Sector-wide implementation assumptions, and upfront capital costs of the Strategy.

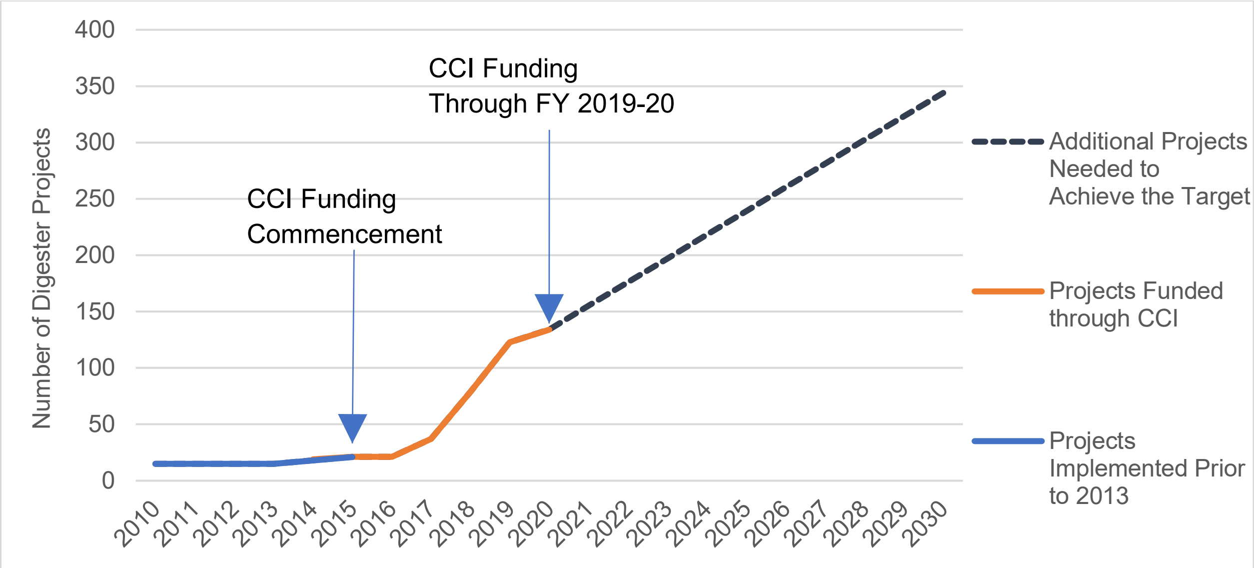


Figure 5. Number of Dairy Digesters in California[22]

Similarly, CDFA's AMMP is a primary source of funds for alternative manure management projects, which also rely heavily on public funds. Project developers are generally smaller dairies that are often not well suited to a digester because of limited financial resources, insufficient herd sizes, or other operational characteristics. While less expensive than a digester, alternative manure management projects on average cost about $600,000 per project. Unlike a digester project, alternative manure management projects do not produce bioenergy or biofuels and are not eligible to generate revenue from environmental credits. Some project developers realize cost savings from bedding purchases or sales of value-added manure products, while others—especially smaller pasture-based operations—are unable to capture any savings or revenue at all.

Infrastructure costs for digester systems producing onsite electricity from biogas including the cost to construct and install an anaerobic digester, construct conditioning facilities to upgrade biogas to necessary specifications, and either convert it to electricity using a reciprocating engine, a microturbine, or a fuel cell. These costs range from approximately $3 million to $17 million depending on the configuration and biomethane utilization option chosen, with average costs between $4 million and $7 million. Infrastructure costs to produce onsite electricity at the lower end assume that a project uses a reciprocating engine generator to produce onsite electricity, while upper end costs (~$17 million) assume the use of a solid oxide fuel cell. Infrastructure costs for digester systems that produce biomethane for pipeline

[22] Numbers shown in Figure 5 do not include the five privately funded dairy digester projects implemented since 2013.

injection (or trucking to injection point or fueling station) including the cost to install an anaerobic digester and a biogas upgrading facility. These costs range from $3 million to $16 million. Project variables include distance to the pipeline and whether the project is on a single dairy or part of a cluster of dairies.

According to CCI reports published to date, DDRDP and AMMP have delivered some of the most cost-effective GHG emissions reductions on a per-metric ton $CO_2e$ basis compared to other CCI funded programs. Table 3 details State, private, and total investments into dairy manure methane emissions reduction projects.

Table 3. Estimated Cost Effectiveness of California Dairy and Livestock Methane Emissions Reductions through 2022

| Program | State Investment ($/MTCO$_2$e) | Private Investment ($/MTCO$_2$e) | Total Investment ($/MTCO$_2$e) |
|---|---|---|---|
| DDRDP | $9 | $20 | $29 |
| AMMP | $61 | $9 | $70 |

Alternative manure management projects can be further subdivided into three project types, including compost bedded pack barns, flush-to-scrape conversions, and solid-liquid separation systems. Methane emissions reduction potential and cost-effectiveness varies across these project types. Table 4 shows the average methane emissions reductions and cost-effectiveness of these alternative manure management project types. According to the table, solid-liquid separation projects have the highest per-project average methane emissions reductions and the lowest implementation costs among these alternative manure management practices. Importantly, site-specific conditions affect methane reductions potential and cost-effectiveness across all project types.

Table 4. Estimated Methane Emissions Reduction Potential and Cost-Effectiveness of Alternative Manure Management Projects through 2022

| AMMP Practices | Reduction per Project (MTCO$_2$e) | Cost-effectiveness ($/MTCO$_2$e) | |
|---|---|---|---|
| | | State Investment | Total Investment |
| Compost Bedded Pack Barn | 1,880 | $73 | $91 |
| Flush-to-Scrape Conversion | 1,420 | $78 | $88 |
| Solid-Liquid Separation | 2,120 | $54 | $58 |

In addition to public funding of digester construction costs, incentive funds and other mechanisms are available to provide ongoing support to project developers. This includes the BioMAT, the Cap-and-Trade Program, and the LCFS Program. The Cap-and-Trade Program allows dairy digester developers to quantify the methane emissions reductions resulting from the installation of a digester using the CARB Compliance Offset Protocol for Livestock Projects. These methane emissions reductions can generate carbon offset credits that developers can sell to capped entities. The Cap-and-Trade Program is designed to encourage capped entities to reduce their GHG emissions while providing flexibility in how those reductions are achieved. The LCFS Program is designed to reduce the average carbon intensity of transportation fuels[23] in California by incentivizing the production and use of low carbon fuels. Alternative fuels like biomethane generate credits in the LCFS program that can be sold to entities generating deficits for supplying high carbon fuels for sale in California.

Dairy digester projects are increasingly participating in the LCFS credit market,[24] where credit prices averaged $192 in 2019.[25] A hypothetical 3,000 milking cow dairy supplying transportation fuel could generate approximately $3.5 million in annual LCFS credit value.[26] Equivalent emissions reductions from the same dairy project might generate $250,000 in annual compliance offset credit value through the Cap-and-Trade Program, using the weighted average price for livestock offset credit transfers.[27,28] However, these potential credit revenue values do not include project-specific variations in additional revenue streams or costs, which may be considerable, even among projects with similar sizes and designs. While dairy digesters offer significant and cost-effective methane emissions reductions, without large-scale public incentives, the rate of adoption would likely decrease greatly. Incentives such as the

[23] Information on current fuel pathways can be obtained through the CARB Current Fuel Pathways Spreadsheet, which is searchable and sortable, by feedstock, fuel, classification, and/or facility name. Accessed in December 2020.

[24] Anaerobic digester projects cannot simultaneously generate both LCFS and Cap-and-Trade credits.

[25] Monthly LCFS Credit Transfer Activity Reports. Accessed in August 2020.

[26] The LCFS credit value represents potential gross revenue from sale of LCFS credits in 2020; this does not include revenues from the sale of fuel, nor the potential revenue from sale of Renewable Identification Numbers (RIN) under the federal EPA Renewable Fuel Standard (RFS). Project development costs are not included in these estimates due to significant variability; costs may include but are not limited to project feasibility, design, and interconnection studies, digester and gas upgrading equipment and installation, and pipeline interconnection infrastructure construction.

[27] Cap-and-Trade Compliance Offset Credits from livestock projects were valued at $13.67 on average per metric ton for transactions occurring in 2019. Summary of Market Transfers Completed in 2019.

[28] Offset credit revenue from livestock projects may vary considerably, even across similarly sized and designed projects resulting from variations in project costs, location, and additional revenue streams. The gross revenue values provided in this Analysis are intended to illustrate potential offset credit revenue for programmatic comparison but may not accurately describe actual net project revenues.

Cap-and-Trade Program, LCFS Program, or RFS Program significantly improve the attractiveness of investment in digester projects.

## Finding 1-3: The 'Social Cost of Methane' Metric Cannot be Used to Determine the Net Societal Benefits or Disbenefits of Methane Emissions Reduction Projects Comprehensively; Methane Reduction Benefits or Disbenefits Vary by Project Type

In addition to mandating SLCP emissions reductions, the Legislature passed AB 197 (Garcia, Chapter 250, Statutes of 2016), which directs CARB to consider the social costs associated with GHG emissions mitigation rules and regulations. The social cost of methane is a measure of the long-term damages caused by emitting one ton of methane in a given year. Using the methodology developed in 2009 by a federal interagency working group convened by the U.S. Council of Economic Advisors and the Office of Management and Budget, CARB staff estimated the potential range in the social cost of methane emissions from 2015 through 2030 in the 2017 Climate Change Scoping Plan.[29] The current analysis focuses on the social costs of methane emissions in 2030 using different discount rates[30] in 2020 dollars[31]—or the value today of preventing environmental damages in the future (Table 5).

The social cost of methane is a metric that can contribute to understanding the societal benefits or disbenefits that accrue from reducing methane emissions. The social cost of methane accounts for damages that occur from the release of methane, including damages due to changes in human health, changes in net agricultural productivity, property damages from increased flood risk, changes in energy system costs, non-market amenities (based on outdoor recreation), and changes to human settlements and ecosystems. Importantly, the models used to estimate the social cost of methane emissions cannot assess the monetary value of all physical, ecological, or economic impacts of climate change. As such, actual societal benefits or disbenefits could differ considerably from the calculated values used in this analysis.

Furthermore, when conducting a complete cost benefit analysis, net societal benefits from a specific project may accrue despite an estimated project disbenefit (negative values shown in Table 5) associated solely with the social value of reducing methane

[29] More information is available in Table 8 in the 2017 Climate Change Scoping Plan.

[30] Discount rate is the rate at which society is willing to trade present benefits for future benefits. Discount rate affects decision making parameters including net present value, cost-effectiveness ratio, internal rate of return, return on investment.

[31] All social cost values have been adjusted to 2020 dollars using the U.S. Bureau of Labor Statistics Historical Consumer Price Index for All Urban Consumers. Accessed in December 2020.

emissions. A methane emissions reduction project may yield a social disbenefit when only accounting for methane emission reductions but may result in substantial improvements to air quality and water quality that are not quantified or monetized by only looking at the social cost of methane. For example, for the dairy and livestock sector, manure management projects such as anaerobic digesters have been successful at reducing methane emissions. The captured methane from digesters can be converted to an energy product, such as renewable electricity produced through fuel cells and internal combustion engine generators, resulting in potential net societal benefits or disbenefits associated with methane emissions reductions before considering other environmental and socioeconomic co-benefits.

Staff used the social costs of methane in Table 5 to estimate the societal benefits and disbenefits of various methane mitigation projects, including fuel cells and internal combustion engine generators at discount rates of 2.5, 3.0, and 5.0 percent. Subtracting the project investment costs from the social cost of methane estimates the net societal benefits or disbenefits of reducing methane emissions by investing in specific manure methane emissions reduction projects, solely from a methane mitigation perspective.[32] Depending on project types, societal benefits or disbenefits from reducing one metric ton of methane vary, ranging from a societal disbenefit of $2,806 to a societal benefit of $1,878. However, as previously noted, this methodology does not fully assess the monetary value of all environmental and socioeconomic co-benefits that may result from establishing these projects, nor does it fully assess any additional societal disbenefits that may arise from non-methane emissions. For example, implementing such strategies may offer improved nutrient management to farms through more precise application of manure solids to crop lands at agronomic rates and potential reductions in synthetic fertilizer use. Conversely, adoption of other methane emissions reductions strategies such as converting biogas to electricity using internal combustion engine generators may increase NOx and other air pollutant emissions, resulting in societal disbenefits. Given that most California dairies are in or near disadvantaged communities that may be disproportionately exposed to air quality impacts, ensuring air quality and other environmental benefits in these communities to the extent feasible is important, independent of the limitations to current social cost of methane estimates.

[32] The overall societal value of a project maybe positive even if a methane emissions reduction project has a social cost of methane disbenefit. Without conducting a comprehensive cost analysis of all environmental and socioeconomic factors, actual net societal benefits of a project remain unknown.

Table 5. Social Cost and Societal Benefits or Disbenefits of Reducing One Metric Ton of Methane Emissions in 2030

| Discount Rate | Social Cost of Methane ($/MT $CH_4$) | Methane Emissions Reduction Cost ($/MT $CH_4$) | | Net Societal Disbenefits (-) or Benefits (+)‡ ($/MT $CH_4$ Reduced) |
|---|---|---|---|---|
| | | Fuel Cell | IC Engine | |
| 5.0% | $949 | $3,755 | $773 | $-2,806 to $176 |
| 3.0% | $1,997 | $3,145 | $648 | $-1,148 to $1,349 |
| 2.5% | $2,496 | $3,002 | $618 | $-506 to $1,878 |

Methane emission reduction scenarios shown in Table 5 assume methane is captured using a dairy digester and destroyed using either fuel cell or an internal combustion engine. These examples provide upper and lower bound estimates for net social benefits and disbenefits. (While pipeline injection projects are the most frequently implemented project types, they are not shown here because costs are highly variable based on project site. However, they would fall within the range shown.)

‡Net societal benefits or disbenefits of reducing one metric ton of methane emissions do not account for all environmental and socioeconomic co-benefits resulting from that reduction.

## Finding 1-4: Feed and Manure Additive Methane Mitigation Strategies Could be Scaled to Help Achieve the 2030 Target

In addition to the manure management practices described above, additional strategies are under development to achieve further reductions from the sector. For example, certain markets have begun using additives that reduce methane emissions from enteric fermentation in ruminants, though use in North America is limited due to pending regulatory approval. Additives to reduce methane emissions from manure management are also under development. Such additives may potentially achieve important, cost-effective methane emissions reductions from dairy and livestock operations while offering increased flexibility and avoiding the significant upfront capital investment associated with installing a digester or implementing an alternative manure management practice.

### Animal Feed Additives

Methane emissions from enteric fermentation in dairy and livestock account for about 30 percent of statewide methane emissions, or approximately 12 $MMTCO_2e$ annually. This presents an opportunity to achieve significant methane emissions reductions, potentially at a cost of approximately $50 per metric ton on a carbon dioxide equivalent basis.[33] Potential strategies to reduce emissions from the digestion process

[33] Assumes use of a product with a ten percent enteric methane emissions reduction effectiveness at an annual cost of approximately $48 per ton ($0.05 per cow per day) on a carbon dioxide equivalent basis.

include diet modifications, feed additives, feed efficiency improvements, and selective breeding of low methane producing animals. Of these, feed additives offer the greatest potential for sector-wide methane emissions reductions because they potentially deliver considerable methane emissions reductions shortly after adoption. In comparison, strategies like diet modifications, feed efficiency improvements, and selective breeding require a relatively long time to achieve significant emissions reductions. Unlike the manure management strategies described above, these strategies can be implemented at existing operations with minimal need to modify facility design and without significant upfront capital requirements. This makes these strategies potentially attractive for dairy and livestock operations, especially rented or leased operations.

Research suggests that certain feed additives may have promising methane emissions reduction potential. For example, 3-Nitrooxypropanol (3-NOP under the commercial name of Bovaer®),[34] has shown an emissions reduction potential between 20 and 40 percent across multiple ruminant species under various testing conditions.[35,36,37] The additive 3-NOP has undergone both laboratory-scale and on-farm testing for effectiveness in reducing methane emissions safely, and for potential impacts on animal health, reproduction, and productivity. It is a chemical product that is currently undergoing US Food and Drug Administration (FDA) approval and may become available within the next few years.[38] Nitrate is another feed additive that has shown an

[34] Mention of trade names or commercial products does not constitute or imply CARB endorsement or recommendation.

[35] Kim, S., Lee, C., Pechtl, H. A., Hettick, J. A., Campler, M. R., Pairis-Garcia, M. D. Beauchemin, K. A., Celi, P., Duval, S. M. (2019). Effects of 3-nitrooxypropanol on enteric methane production, rumen fermentation, and feeding behavior in beef cattle fed a high-forage or high-grain diet. *Journal of Animal Science*, 97(7), 2687–2699.

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[38] Mitloehner, F. M., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

emissions reduction potential between 10 and 20 percent.[39,40,41,42,43] However, existing research is insufficient to conclude that microbes in the rumen will acclimate to increased nitrate without causing adverse animal health impacts. Agolin® Ruminant,[44] an essential oil mix, has shown methane reduction potential between 10 and 20 percent for dairy cows without impacting milk yield and composition. Mootrol® Ruminant, a pelleted product made from garlic and orange extract, has also shown methane mitigation potential in both *in vitro* and *in vivo studies* [45,46] and researchers are currently investigating its long-term effectiveness in beef cattle. Both Agolin® Ruminant and Mootral® Ruminant are commercially available and are Generally Regarded As Safe (GRAS)[47] by the FDA. Novel additives, such as lemongrass and seaweed[48] have also shown emissions reduction potential but lack sufficient *in vivo* (animal) studies to demonstrate long-term effectiveness and potential impacts on

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[41] Raleng, A. O. (2008). The Potential of Feeding Nitrate to Reduce Enteric Methane Production in Ruminants.

[42] Meller, R. A., Wenner, B. A., Ashworth, J., Gehman, A. M., Lakritz, J., Firkins, J. L. (2019). Potential roles of nitrate and live yeast culture in suppressing methane emission and influencing ruminal fermentation, digestibility, and milk production in lactating Jersey cows. *Journal of Dairy Science*, 102(7), 6144-6156.

[43] Zijderveld, S. V., Gerrits, W., Dijkstra, J., Newbold, J., Hulshof, R., & Perdok, H. B. (2011). Persistency of methane mitigation by dietary nitrate supplementation in dairy cows. *Journal of dairy science*, 94(8), 4028-38.

[44] Carrazco, A. V., Peterson, C. B., Zhao, Y., Pan, Y., McGlone, J. J., DePeters, E. J., Mitloehner, F. M. (2020). The Impact of Essential Oil Feed Supplementation on Enteric Gas Emissions and Production Parameters from Dairy Cattle. Sustainability, 12(24), 10347

[45] Eger, M., Graz, M., Riede, S., Breves, G. (2018). Application of Mootral™ reduces methane production by altering the Archaea community in the rumen simulation technique. Frontier in microbiol, 9, 2094. doi: 10.3389/fmicb.2018.02094

[46] Roque, B. M., Van Lingen, H. J., Vrancken, H., Kebreab, E. (2019). Effect of Mootral—a garlic- and citrus-extract-based feed additive—on enteric methane emissions in feedlot cattle. Translational Animal Science, 3(4), 1383–1388

[47] "GRAS" is an acronym for the phrase Generally Recognized As Safe by the FDA. Under sections 201(s) and 409 of the Federal Food, Drug, and Cosmetic Act (the Act), any substance intentionally added to food is a food additive, that is subject to premarket review and approval by FDA, unless the substance is generally recognized, among qualified experts, as having been adequately shown to be safe under the conditions of its intended use, or unless the use of the substance is otherwise excepted from the definition of a food additive (https://www.fda.gov/food/food-ingredients-packaging/generally-recognized-safe-gras).

[48] Abbott, D. W., Aasen, I. M., Beauchemin, K. A., Grondahl, F., Gruninger, R., Hayes, M., Huws, S., Kenny, D. A., Krizsan, S. J., Kirwan, S. F., Lind, V., Meyer, U., Ramin, M., Theodoridou, K., von Soosten, D., Walsh, P. J., Waters, S., Xing, X. (2020). Seaweed and Seaweed Bioactives for Mitigation of Enteric Methane: Challenges and Opportunities. *Animals*, *10*, 2432.

productivity and human or animal health.

To better understand the potential contribution of feed additives in achieving the 2030 target, staff evaluated six potential enteric methane emissions reduction scenarios that focused on the use of feed additives. These scenarios shown in Figure 6 (below) illustrate potential annual methane emissions reductions resulting from the use of feed additives with methane mitigation effectiveness of 10, 30, and 50 percent,[49] representing the low, medium, and high potential of different feed additives, at adoption rates of 50 and 75 percent. The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional projects will be implemented.[50] As the figure shows, if solely enteric feed additives are utilized beyond 2022 and no additional manure methane projects are implemented, a feed additive with a methane emissions reduction effectiveness of at least 50 percent would need to be adopted by at least 75 percent of ruminants in the sector to achieve the 2030 target.

[49] These values represent the enteric methane mitigation effectiveness of various feed additives. Ten percent represents a conservative estimate of mitigation effectiveness for currently available products; thirty percent represents a median estimated effectiveness for 3-NOP, which shows mitigation potential between 20-40 percent, and is expected to become commercially available in the near future; fifty percent represents a conservative estimate for the most effective emerging approaches, such as seaweed.

[50] Additional manure methane emissions reduction projects are expected to be developed but have been omitted from Figure 6 to illustrate the potential of feed additive-based enteric methane emissions reductions.

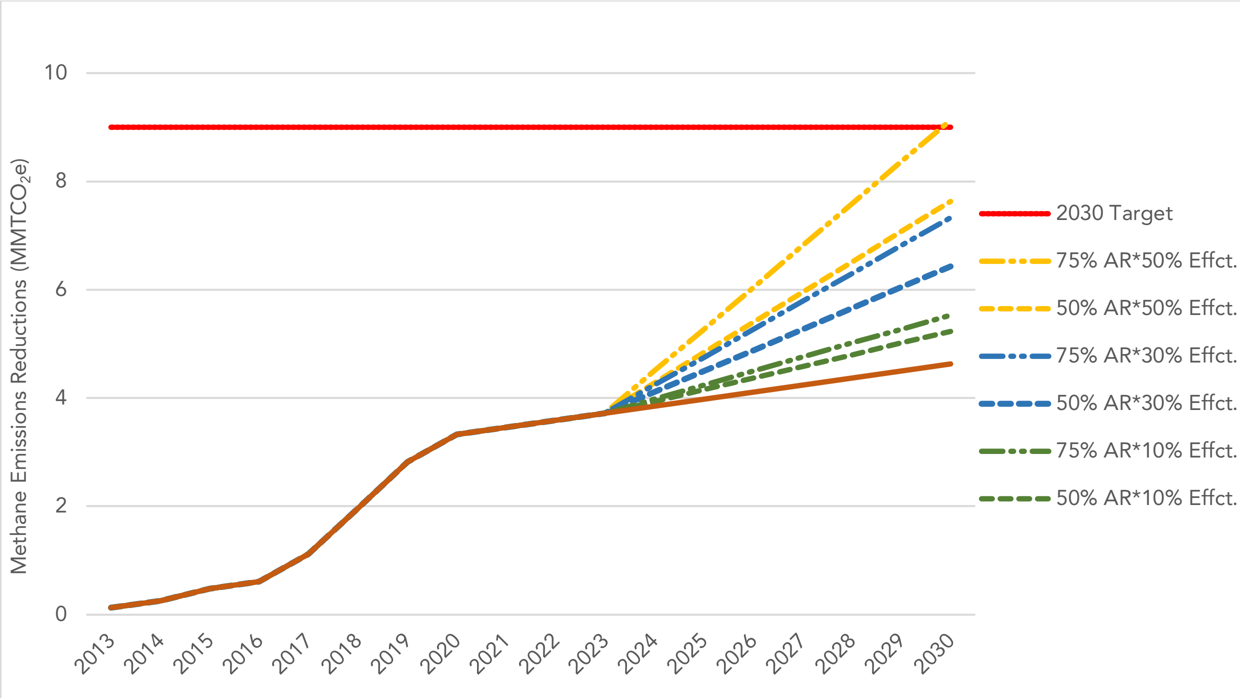


Figure 6. Projected Annual California Dairy and Livestock Sector Enteric Methane Emissions Reductions through 2030 Under Various Feed Additive Adoption Rates (AR) and Methane Mitigation Effectiveness (Effct.)

**Manure Additives to Reduce Methane Emissions**

Most of California's manure methane emissions originate from anaerobic manure treatment and storage lagoons. Manure additives can potentially modify environmental conditions in manure treatment and storage facilities, including but not limited to pH, redox potential, and microbial composition, to levels that are less conducive to methane production. Examples of potential manure additives include incorporation of biochar or proprietary lagoon additives, as well as the use of manure acidification. However, these strategies require additional investigation of their methane emissions mitigation effectiveness, applicability to California dairy and livestock manure management systems, and potential unintended impacts to air or water quality. For example, biochar has been shown to reduce methane emissions through incorporation into manure slurry; however, it may not be practical or effective in liquid manure management systems that are predominant on California dairy operations. Similarly, acidification of manure slurry may be effective at reducing methane emissions but may be impractical for California operations due to the need for large acid volumes that require special handling and safety equipment. CARB will continue tracking developments in manure additives as they become available, especially those with long-term studies that detail potential methane emissions mitigation effectiveness and environmental co-benefits.

## Finding 1-5: Dairy and Livestock Sector May Fall Short of the 2030 Target absent an Enteric Strategy and Sufficient Public Funds[51]

To estimate potential emissions reductions from manure management projects under various public funding scenarios, CARB staff developed scenarios to extrapolate funding outcomes through 2030. These projections are based on project development costs and emission reductions described above, and do not account for environmental credit values on project costs. The impact of LCFS and RFS environmental credit prices on project economics is discussed in the following section. Figure 7 (below) illustrates potential methane emissions reductions achievable through the combination of an available enteric strategy, changes in animal populations, and from manure management projects at different levels of CCI funding assumptions.52 The 2030 target is shown as a red dotted line at the top of the graph. Potential methane emissions reductions from average animal population changes (discussed in Finding 1-1) are shown as a dark blue dashed line at the bottom of the graph.

[51] Trends discussed in this section are based on publicly available data wherever possible. In instances where available information was incomplete or insufficient, CARB staff used reasonable and conservative assumptions based on existing trends and available information.

[52] Funding projections assume that DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice.

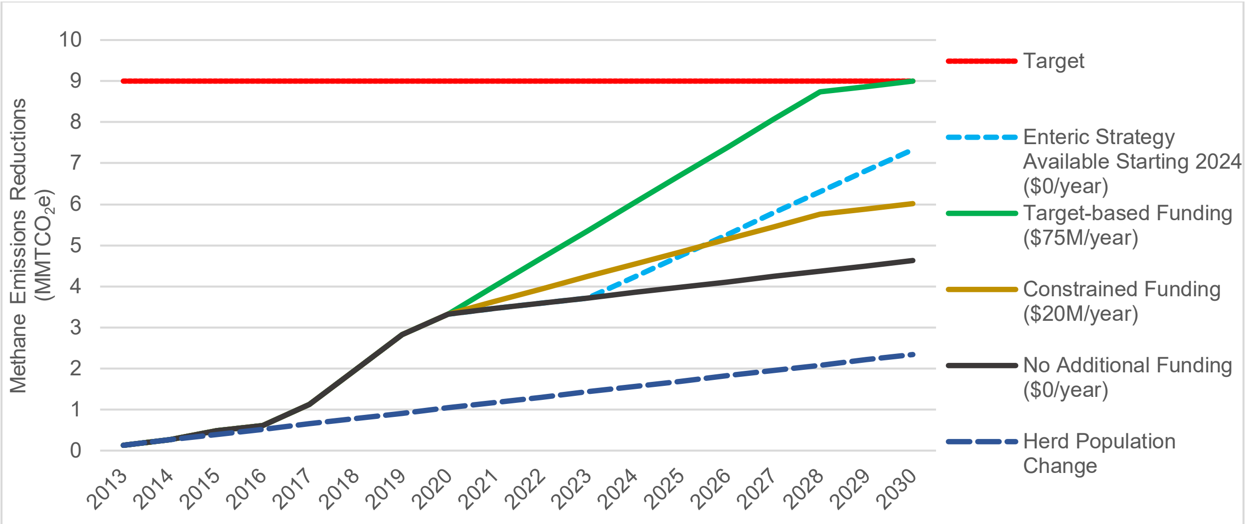


*Figure 7. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030*[53][54]

Additionally, Figure 7 shows methane emissions reductions expected under three different funding scenarios from FY 2020-21 through FY 2027-28 (green, brown, and dark gray solid lines).[55] It also shows potential emissions reductions from herd population changes and a potential enteric strategy (dark and light blue dashed lines, respectively). The funding scenarios assume that the observed decline in animal populations will continue at a constant rate through 2030. While emissions reductions attributable to a potential enteric strategy are shown in the figure, those emissions reductions are not accounted for in any of the funding scenarios above.

Each scenario includes emissions reductions expected from changes in population through 2030 as well as reductions expected from DDRDP and AMMP projects funded through FY 2019-20.

***Incentive Funding Scenario 1: No Additional Funding***

This scenario assumes that no additional appropriations of local, state, and federal funds are available for DDRDP and AMMP beyond FY 2019-20. Methane emissions reductions expected under Scenario 1 are shown in Figure 7 by the gray line labeled "No Additional Funding." This scenario assumes that funding is the limiting factor in new projects coming online. The y-axis difference between this line and the population

[53] Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[54]Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[55] Funding levels do not reflect private match funding that is required for DDRDP projects.

change line represents emissions reductions attributed mostly to State funds, emphasizing their importance in achieving the methane emissions reductions through 2022. Staff estimates this scenario will achieve 4.6 $MMTCO_2e$ of methane emissions reductions by 2030, falling 4.4 $MMTCO_2e$ short of the 2030 target.

*Incentive Funding Scenario 2: Constrained Funding*

This scenario assumes that consistent annual appropriations of $20 million for DDRDP and AMMP from FY 2020-21 through FY 2027-28. Methane emissions reductions expected under Scenario 2 are shown by the yellow line in Figure 7. This scenario assumes that allocations between DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice. With constrained funding through FY 2027-28, all funded projects will likely be operational by 2030. Staff estimates this scenario will achieve 6.0 $MMTCO_2e$ of methane emissions reductions by 2030, falling 3.0 $MMTCO_2e$ short of the 2030 target.

*Incentive Funding Scenario 3: Target-Based Funding*

This scenario assumes annual appropriations of $75 million for DDRDP and AMMP beyond FY 2019-20 through FY 2027-28—a level sufficient to achieve the 2030 target through manure emissions mitigation projects. This scenario accounts for a 20 percent project cost increase over current levels due to projects with smaller cattle populations and increased distances to the nearest natural gas pipeline with sufficient capacity. Methane emissions reductions expected under Scenario 3 are shown by the green line in Figure 7. Staff estimate that this scenario will achieve the 2030 target of 9.0 $MMTCO_2e$.

*Enteric Strategy Scenario*

Staff also estimated that a scientifically proven, cost-effective, safe, and consumer-accepted enteric methane mitigation strategy may be commercially available within the next three to five years to help achieve the 2030 target, shown by the light blue dashed line near the top of Figure 7. This assumes adoption of a feed additive with 30 percent enteric methane mitigation potential across ruminant species in California starting in 2024, and a linear annual adoption rate of approximately 11 percent through 2030, totaling 75 percent of the ruminant population.

For simplicity, the target-based funding scenario assumes that no enteric strategy will be available before 2030. Similarly, the enteric strategy scenario described below assumes that no public funding will be available beyond FY 2019-20. While both scenarios are based on reasonable estimates and are illustrative of potentially achievable methane emissions reductions, actual methane emissions reductions may vary.

While these scenarios focus on the outcomes of public investments and required private match funding to meet the 2030 target, revenue available through the California Cap-and-Trade Program and LCFS Program, as well as the federal RFS Program, can substantially reduce or eliminate the need for public funding of these projects. These revenue streams have become strong drivers of anaerobic digestion projects, helping ensure their long-term operation and financial stability.

### *Alternative Manure Management Practice Scenarios*

Staff also evaluated the potential for different adoption rates of alternative manure management practices at California dairies to help achieve the 2030 target. As above, staff used average methane emissions reduction values to calculate potential reductions from various numbers of additional projects at California dairies. Staff also assumed that the approximately 280 dairy operations that had already implemented a manure methane strategy would not incorporate additional manure or implement enteric methane reduction strategies, leaving approximately one thousand dairies available for project implementation. Staff evaluated potential annual methane emission reductions resulting from alternative manure management project adoption under three different scenarios with 250, 500, and 750 additional dairies.

The estimated annual emissions reductions for each scenario are shown in Figure 8 (below). The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional digesters projects and no enteric methane reduction strategies are implemented, showing the potential impact of alternative manure management projects on progress towards the 2030 target. The blue, yellow, and gray lines show expected annual emissions reductions from implementing new alternative manure management practices on 250, 500, and 750 additional dairies, respectively. On their own, none of these scenarios are estimated to provide sufficient methane emissions reduction to achieve the 2030 target.

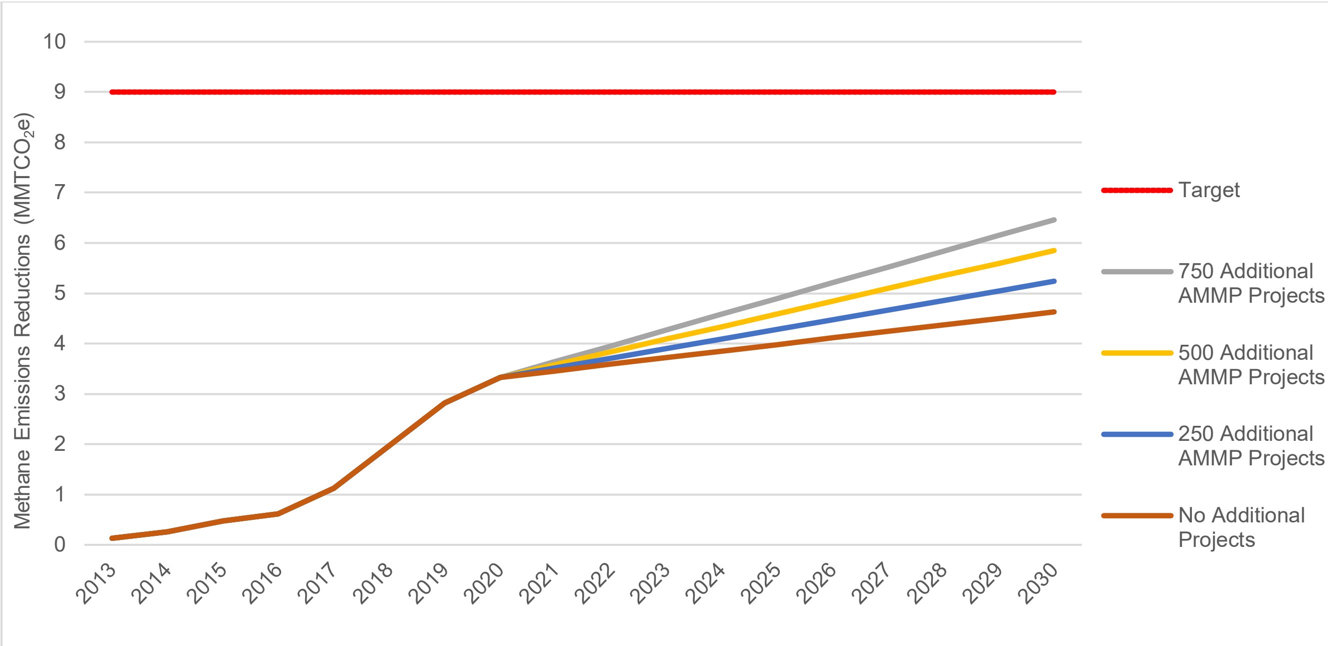


Figure 8. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030 Resulting from Implementing Additional Alternative Manure Management Projects

However, alternative manure management practices are important strategies that may provide significant additional environmental co-benefits. First, these practices may be more broadly implemented across the sector, including at small- and medium-sized dairies due to reduced upfront capital and maintenance costs compared to digesters. They may also provide flexibility to dairies with configurations that make digester implementation infeasible. Second, implementing certain alternative manure management practices alone or in combination with practices incentivized by other programs such as State Water Efficiency and Enhancement Program may provide additional water conservation and GHG benefits. These practices include conversion to scrape manure management, use of sub-surface drip irrigation, or pasture dairy conversion. Third, alternative manure management practices may improve solids and nutrient management, reduce nitrate leaching and improve water quality, reduce chemical fertilizer use, increase crop yield, and provide cost savings to dairy and livestock operations.

In addition to solid-liquid separation, compost bedded pack barns, conversion to scrape manure management, and pasture dairy conversion, stakeholders have proposed eligibility for other alternative manure management practices. These practices include but are not limited to manure acidification, vermifiltration, advanced chemical flocculation, and dissolved air flotation. Given the emergent nature of these strategies, additional research or observation at California dairy and livestock operations is necessary to evaluate methane reduction potential, long-term effectiveness, and potential unintended environmental impacts. Staff will continue monitoring deployment of these and other promising alternative manure management practices as they become available.

In some cases, alternative manure management practices can be combined with digesters to achieve greater emissions reductions than either strategy might on its own. Solid-liquid separators are commonly installed in conjunction with covered lagoon digesters to remove coarse solids, potentially reducing digester maintenance needs. These separated solids can be used for animal bedding, providing cost savings to the farmer. These same solids and nutrients can also be further processed into compost or soil amendment for onsite land application or export offsite, potentially generating additional revenue or cost savings while reducing chemical fertilizer needs. Stricter control of solids and nutrients can also help minimize water quality impacts by reducing nutrient leaching to groundwater.

## Finding 1-6: Dairy Digester Development Will Need Significant Policy and Incentive Support, Providing Additional Methane Emissions Reduction Potential and Biomethane Supply

Generating environmental credits through the California Cap-and-Trade Program, LCFS Program, and federal RFS Programs can provide important revenue streams to dairy operators and project developers. As a result, these credit values are likely to drive additional dairy digester project development, methane emissions reductions, and increases in-State biomethane supply.

To estimate statewide dairy biomethane supply and production cost, staff reviewed existing literature and reports[56,57,58] as well as recent dairy population data from Regional Water Quality Control Board permits and annual reports. As part of that evaluation, and to refine supply estimates, staff adjusted underlying datasets to reflect facilities that had implemented an alternative manure management practice[59] or had closed. Staff assume that the remaining dairies can implement a digester project and

[56] Jaffe, A. M. (2016). Final Draft Report on The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute.

[57] Jaffe, A. M., Dominguez-Faus, R., Ogden, J., Parker, N. C., Scheitrum, D., McDonald, Z., Fan, Y., Durbin, T., Karavalakis, G., Wilcock, G., Miller, M., Yang, C. (2017). The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology.

[58] Parker, N., Williams, R., Dominguez-Faus, R., & Scheitrum, D. (2017). Renewable natural gas in California: An assessment of the technical and economic potential. *Energy Policy*, *111*, 235-245.

[59] Facilities with alternative manure management practices implementation are less likely to divert animal waste to anaerobic digesters for biomethane production.

estimate that at least an additional 210 digester projects are necessary to achieve the target (in addition to 210 alternative manure management projects).

The six project technology options below describe potential pathways to use methane captured in a digester. These options include onsite electricity production using a reciprocating engine, a microturbine, or a solid oxide fuel cell, as well as direct injection into a natural gas pipeline from a single dairy, cluster of dairies, or through trucking to an existing interconnection point where it can displace fossil natural gas. While these technology options may result in similar methane emissions reductions, criteria pollutant performance, potential carbon intensities, project costs, and project revenues may vary considerably. Staff assume that project developers will select the digester technology option that is most suitable for their facility.

### *Anaerobic Digestion Technology Option 1: Reciprocating Engine Generator for Electricity Generation*

This technology option involves using a reciprocating engine generator to generate electricity on site using biogas and offset fossil fuel-derived electricity for a variety of end uses, including but not limited to electric vehicle charging.[60] However, reciprocating engine generators also result in new sources of air pollutant emissions that adversely impact regional air quality, attainment of ambient air quality standards, and public health outcomes. For example, the San Joaquin Valley is home to the majority of the State's dairy and livestock operations, it has among the worst air quality in the country and is home to many of the State's most disadvantaged and low-income communities. Given the potential for further impacts, utilizing even the cleanest reciprocating engine generator is the least desirable option.

### *Anaerobic Digestion Technology Option 2: Microturbine for Electricity Generation*

This technology option involves using a microturbine certified under the CARB Distributed Generation (DG) Certification Program to generate electricity using biogas. The DG Certification Program requires manufacturers of electrical generation technologies that are exempt from air district permit requirements to certify their technologies to specific criteria pollutant emission standards before selling products in California. Common DG technologies certified under this program include fuel cells and microturbines. Microturbines have higher costs compared to reciprocating engine generators but produce fewer air pollutant emissions, and therefore have fewer associated impacts on regional air quality and public health. As with all onsite

[60] The LCFS Program includes three California dairies projects that use reciprocating engine generators, one of which received a -630.92 g/MJ carbon intensity score, the lowest LCFS carbon intensity score to date.

electricity generation projects, microturbines do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

### *Anaerobic Digestion Technology Option 3: Fuel Cell for Electricity Generation*

This technology option involves using a fuel cell to generate onsite electricity using biogas to support electric vehicle charging.[61] Fuel cells generate onsite electricity with very low air pollutant emissions, especially when compared to emissions associated with reciprocating engine generators. These projects provide electricity using biogas that avoids up to 90 percent of the NOx and up to 80 percent of the particulate matter emissions resulting from other combined heat and power technologies on a life-cycle basis.[62] Fuel cells installed at dairies have the potential to be certified for ultra-low carbon intensity scores, and the potential LCFS credit revenue may make them competitive in the long-term. As with all onsite electricity generation projects, fuel cells do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

### *Anaerobic Digestion Technology Options 4a & 4b: Onsite Injection of Biomethane into a Natural Gas Pipeline*

These technology options include either single dairy or cluster pipeline interconnection projects. These are the most common options and involve biogas capture, upgrading to pipeline biomethane specifications, and injection into a natural gas pipeline. These projects reduce GHG emissions further when they replace fossil natural gas. They also avoid onsite combustion for electricity generation and the associated onsite air pollutant emissions and public health impacts. As a result, these projects are preferable to onsite combustion projects but may not be feasible due to factors including distance to the nearest natural gas pipeline with enough capacity, and whether the facility is part of a cluster. Project cost between these two categories differ notably, with single dairy projects costing considerably more compared to cluster projects due to lack of ability to share upgrading facility and pipeline extension costs.

### *Anaerobic Digestion Technology Option 5: Trucking Biomethane to an Existing Interconnection Point for Injection into Natural Gas Pipeline*

This technology option involves trucking biomethane to the closet injection point or natural gas vehicle refueling station. This option assumes that biomethane is

[61] Two DDRDP projects use Bloom Energy solid oxide fuel cells.
[62] An Assessment of Energy Technologies and Research Opportunities: Chapter 4: Advancing Clean Electric Power Technologies September 2015.

transported by a zero-emissions electric or natural gas heavy duty truck with few criteria pollutant (including oxides of nitrogen) and particulate matter emissions compared to a diesel heavy-duty truck. Using natural gas or electric heavy-duty trucks reduces criteria pollutant emissions and avoids emissions of harmful diesel particulate matter from biomethane transport, with negligible impact on project cost compared to using a diesel truck. Trucking biogas, referred to as a "virtual pipeline," may reduce project costs and provide flexibility compared to construction of dedicated pipelines. It also mitigates the risk of stranded infrastructure in the event of reduced demand from a site-specific large downstream consumer (e.g., milk processing operation). Trucking biomethane to existing injection points may be a cost-effective delivery option that results in fewer emissions than reciprocating engine generator and microturbine projects. However, it will also increase vehicle miles traveled, likely in disadvantaged communities, so incentives or regulatory approaches should encourage facilities to reduce reliance on trucking where feasible and use of zero emission vehicles or natural gas heavy-duty trucks when necessary.

### *Potential Biomethane Supply from Anaerobic Digestion*

The preceding anaerobic digestion technology options describe potential pathways to deliver biomethane to market through electricity generation or pipeline injection. This section illustrates the potential biomethane supplied to market and associated costs under each of these options in a baseline scenario, and under various environmental credit price scenarios. Figure 9 below shows potential biomethane supply and market delivery cost under a baseline scenario, which is absent any State or federal financial incentives. The dashed red line shows expected biomethane supply by 2022, approximately 4.7 trillion British thermal units (Btu). The dashed black line indicates the estimated amount of biomethane supply (~13.5 trillion Btu) needed to achieve the 2030 target. Without State or federal financial incentives like the State's LCFS Program or the federal RFS Program, none of the technology options described above (Figure 9) are financially viable.

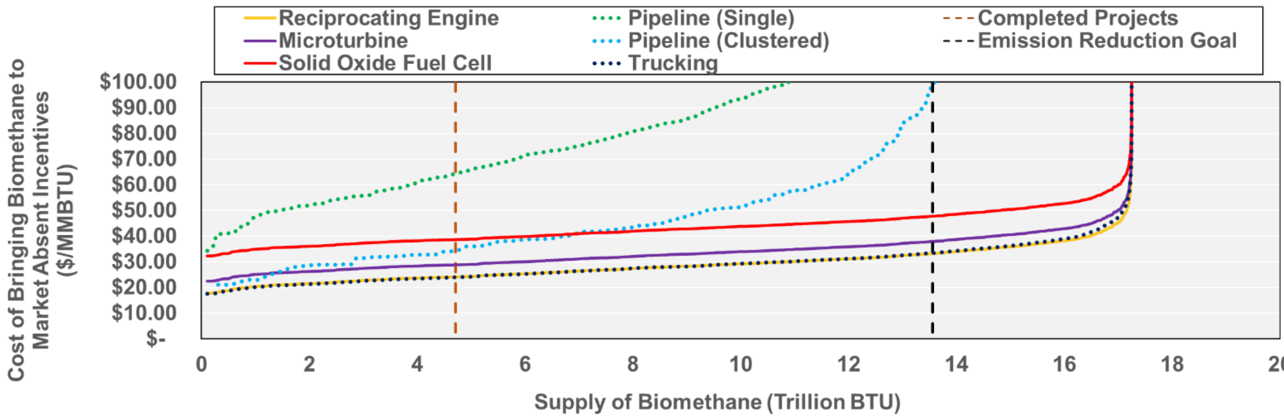


Figure 9. Biomethane Supply and Market Delivery Cost under Different Technology Options absent Federal and State Incentives

Figure 9 illustrates the cost of bringing biomethane to market under each technology option absent any public incentives (e.g., CCI funds, Cap-and Trade Program compliance offset credits, LCFS credits, RFS RIN credits). The costs portrayed for this curve and the subsequent supply curves in Figures 10 through 12 show levelized cost, and therefore includes financing assumptions for the digester projects as well as the additional capital and operating expenses associated with the technology that uses the dairy gas produced through anaerobic digestion. For instance, the levelized cost of pipeline projects is inclusive of the covered lagoon and anaerobic digestion system, upgrading the gas, building the pipeline, and injecting the gas into the pipeline. For the other technologies, the costs include any upgrading costs, as well as any additional equipment costs (e.g., solid oxide fuel cell) required to bring the gas to market.

In general, the supply curves for pipeline-based technologies have a substantially greater upward slope. Pipeline interconnection distances vary for each facility, and facilities that are further away from pipelines will have higher costs to build the network relative to facilities that are closer to pipeline interconnection points. Additionally, facilities that produce more biomethane (i.e., larger facilities) will be able to recoup fixed pipeline costs by distributing these costs over larger quantities of produced biomethane over time. As such, the lowest cost pipeline projects will generally be for large facilities that are closer to pipeline interconnections. The other technologies largely scale linearly with the size of the facility. As such, the slope for non-pipeline technologies is generally more gradual.

The cost to deliver biomethane to market may be as low as $30 per MMBtu if trucked to an existing pipeline interconnection or used to produce onsite electricity using a reciprocating engine generator. In contrast, delivering biomethane to market may cost as much as $100 per MMBtu for pipeline injection at a cluster of dairies—the costliest option with sufficient capacity to achieve the 2030 target. For comparison, in October 2020 wholesale fossil natural gas prices on Henry hub were approximately $3 per MMBtu, but has increased to approximately $5 per MMBtu in October 2021. Given that the price of fossil natural gas is approximately one tenth to one sixth that of biomethane, it is uneconomic to utilize biomethane without incentives beyond sale price.

Staff used biomethane delivery costs and volumes from Figure 9 to estimate potential costs for implementing at least 210 additional digester projects necessary to achieve the 2030 target. To be conservative, staff developed estimates using expected biomethane delivery costs from the 2030 target line to reduce potential underestimation of the total cost to achieve the target for feasible scenarios. Project costs on this line are expected to be the highest over time and assumes that more financially feasible projects have already been implemented.

To bound the potential total cost of achieving the 2030 target, staff used the solid oxide fuel cell scenario costs as an upper bound and costs associated with trucking biomethane to an existing interconnection point and producing onsite electricity using a reciprocating engine generator as the lower bound value. Though cluster pipeline projects may also potentially deliver sufficient biomethane to meet the 2030 target, this scenario is unlikely to be implemented at enough facilities to achieve the target. The costs associated with constructing additional pipelines to supply enough biomethane to achieve the target make it increasingly unlikely that the more costly projects would be implemented. Instead, it is more likely that these facilities will choose the lower cost options of generating onsite electricity or trucking biomethane to an existing interconnection point. As such, it is inappropriate to use direct pipeline injection as an upper cost bound.

Staff also assumed, as previously discussed in Finding 1-1, that at least 210 alternative manure management projects may be implemented at an assumed per project cost of $0.6 million, resulting in a total cost of $0.1 billion. Staff added this $0.1 billion to the total costs associated with the lower and upper bound cost of implementing the additional 210 digester projects. Based on these assumptions, the estimated total cost to achieve the 2030 target range from $0.8 to $3.7 billion absent any public incentives. The 2030 target may also be achieved solely through implementation of as few as 230 additional digester projects costing between $0.7 and $3.9 billion.

With public incentives like LCFS credits and RFS RINs, the need for upfront public investment in digester projects[63] may be reduced or even eliminated, assuming project developers will have access to debt financing for upfront project construction cost. These incentives can be sufficient to offset project development, operational, and financing costs in some cases depending on the level of incentive available, providing a positive project revenue stream and making the project financially viable.

Staff evaluated the same methane emissions reduction technology options used in the baseline scenario above to estimate biomethane supply and cost under various combinations of LCFS and RFS RIN credit prices.[64,65,66] These credit value scenarios range from $150-$200 per credit for LCFS and $0-$2 per RIN. Table 6 shows potential credit values from delivering one MMBtu of biomethane to market at these price ranges under different technology options. Potential credit values at such levels may make these projects competitive with fossil natural gas and with other sources of biomethane.

Table 6. Potential Environmental Credit Value ($) from Producing One MMBtu of Biomethane under Different Technology Options at Various LCFS and RIN Credit Prices[67]

| Biomethane Delivery Option | LCFS $150 | | | LCFS $200 | | |
|---|---|---|---|---|---|---|
| | RIN $0 | RIN $1 | RIN $2 | RIN $0 | RIN $1 | RIN $2 |
| Reciprocating Engine | $41 | $41 | $41 | $55 | $55 | $55 |
| Microturbine | $55 | $55 | $55 | $74 | $74 | $74 |
| Solid Oxide Fuel Cell | $64 | $64 | $64 | $85 | $85 | $85 |
| Pipeline (Single or Cluster) | $49 | $62 | $75 | $66 | $79 | $92 |
| Trucking | $44 | $57 | $70 | $59 | $72 | $85 |

[63] Alternative manure management projects are not eligible for State and federal biomethane incentive programs because, while they do reduce dairy methane emissions, they do not produce biomethane.

[64] Assumes D3 cellulosic RIN

[65] Electricity generation projects are not currently able to generate RFS RIN credits and have been assigned a $0.00 RIN price across all evaluated credit price scenarios.

[66] Offset credits are not evaluated because the LCFS credits value is considerably more than the Cap-and-Trade program.

[67] The assumed carbon intensities, energy efficiency rating (EER), and percent efficiency rating for the identified biomethane delivery options are as follows:

- Reciprocating Engine: -490 grams per mega Joule (g/MJ), 3.4 EER, 32% efficiency
- Microturbine: -490 g/MJ, 3.4 EER, 44% efficiency
- Solid Oxide Fuel Cell: -400 g/MJ, 3.4 EER, 57% efficiency
- Pipeline (Single or Cluster): -230 g/MJ, 0.9 EER, 100% efficiency
- Trucking: -230 g/MJ, 0.9 EER, 100% efficiency

Figure 10 through Figure 12 below illustrate the potential biomethane supply and market delivery cost under three different combinations of LCFS and RIN credit prices. These scenarios illustrate a potential lower bound, a potential upper bound, and a scenario with medium credit values. They are described in greater detail below. Values below $0.00 on the y-axis provide positive revenue to projects making them financially viable because revenues exceed project costs. Conversely, values above $0.00 indicate that revenues are insufficient to offset project costs, making the projects infeasible because supply costs are too high.

***Environmental Credit Price Scenario 1: $150 LCFS and $0 RIN***

This scenario estimates biomethane supply and production cost assuming values of $150 for LCFS credits and $0 for RIN credits (Figure 10). Under this scenario, single dairy pipeline projects can supply approximately 1 trillion Btu of biomethane to the market, falling far short of the required volume to meet the 2030 target. Previously funded projects exceeded this capacity, which suggests that future single pipeline injection projects are not viable at these prices.

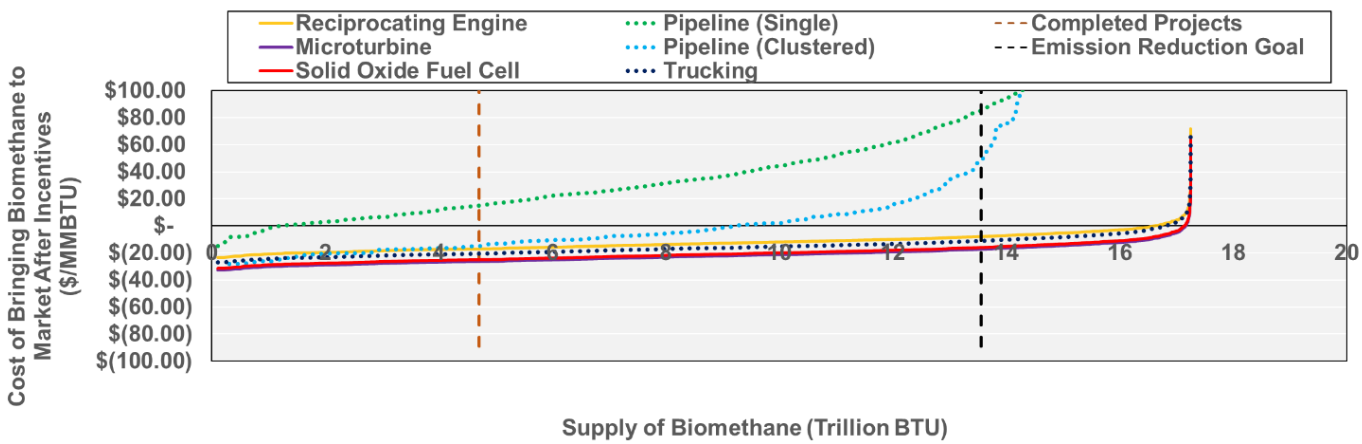


Figure 10. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $150 and $0, Respectively

For comparison, clustered pipeline projects can supply approximately 9 trillion Btu. While a significant increase over the single pipeline projects, this still falls short of the volume required to meet the target. Under Scenario 1, both the single and cluster pipeline injection options are unable to bring sufficient dairy biomethane to market to meet the target without additional incentives.

However, biomethane-to-electricity projects and trucking biomethane to existing interconnection points may provide enough biomethane volume to the market to meet the 2030 target. In this scenario, the solid oxide fuel cell technology option generates the highest revenue with an LCFS environmental credit value of $64 per

MMBtu. Biogas-to-electricity projects that use reciprocating engines and microturbines result in less revenue but cost less than solid oxide fuel cell projects.

### *Environmental Credit Price Scenario 2: $200 LCFS and $1 RIN*

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $1 for RIN (Figure 11). Under this scenario, single-dairy pipeline projects can cost-effectively supply approximately 8 trillion Btu of biomethane to the market, which is a considerable increase over Scenario 1, but still more than 5 trillion Btu short of the 2030 target. Cluster pipeline injection projects will not be able to cost-effectively supply sufficient biomethane to achieve the target either, falling short by approximately 1 trillion Btu. Consistent with Scenario 1, biogas-to-electricity, solid oxide fuel cell projects, and biomethane trucking projects can supply sufficient biomethane to achieve the 2030 target, with the latter two offering the considerably higher credit revenue. Under this scenario, only dairy pipeline injection projects would require additional incentives to achieve the target.

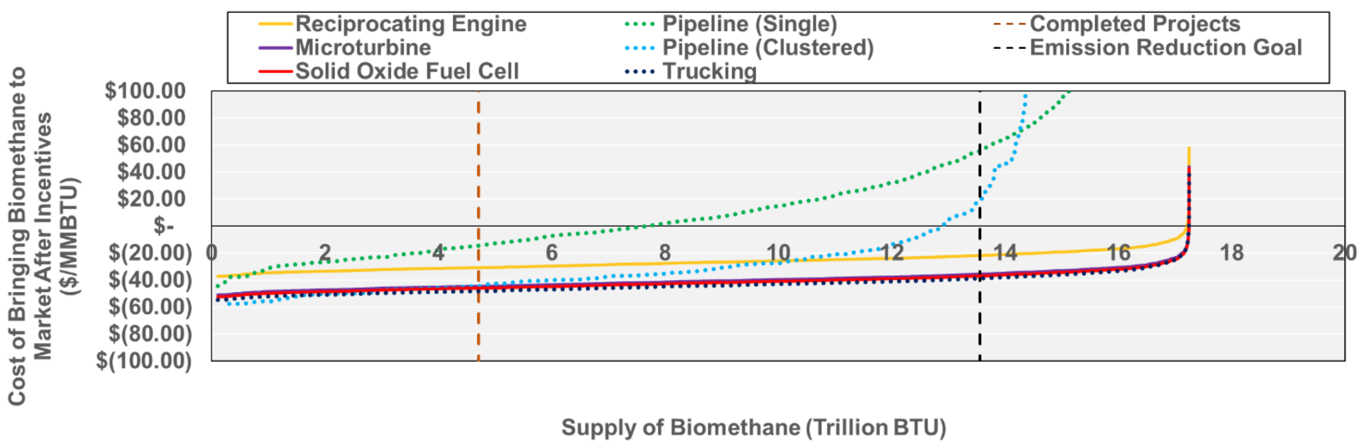


Figure 11. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $200 and $1, Respectively

### *Environmental Credit Price Scenario 3: $200 LCFS and $2 RIN*

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $2 for RIN (Figure 12). In this scenario, single-dairy pipeline injection projects can cost-effectively bring about 10 trillion Btu of biomethane to market, the highest volume across scenarios but still fall short of the target by 3 trillion Btu. Cluster pipeline injection projects can cost-effectively bring over 13 trillion Btu of biomethane to market, nearly achieving the target. Trucking projects are the most cost-effective overall resulting from credit revenue available and relatively low project development costs. Solid oxide fuel cell projects are another cost-effective option given the estimated credit value. Under this scenario, all but pipeline injection projects can cost effectively bring enough biomethane to market without the need for additional incentives.

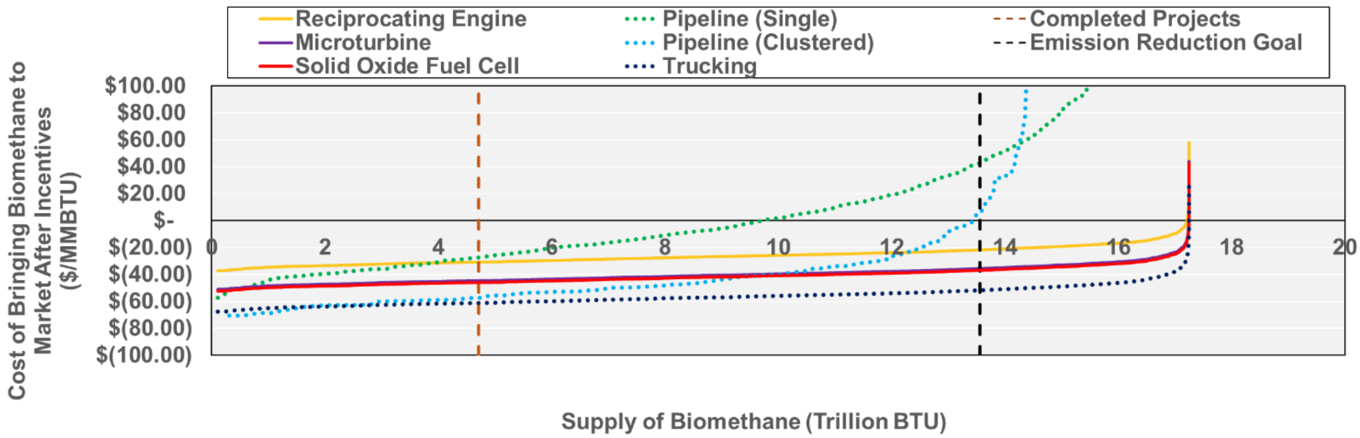


Figure 12. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credits Prices of $200 and $2, Respectively

***Current Federal and State Environmental Credits, Combined with Project Development Incentives, May Be Sufficient to Support Dairy Biomethane Projects***

As the scenarios above illustrate, LCFS and RFS RIN credit prices are significant drivers of economic feasibility for anaerobic digestion projects at California dairy and livestock operations. This is especially true for projects that do not receive public funding. It is also clear that, given sufficient and sustained credit prices, most of these project types can cost-effectively supply sufficient biomethane to achieve the 2030 target with no additional public incentive funding, potentially reducing the need for those resources.

While each of these anaerobic digestion scenarios can potentially generate revenue or even profits to support construction and operation of digester projects, LCFS and RFS credit markets may be perceived as relatively uncertain as compared to conventional project financing options. Developers unable to obtain debt financing will need additional equity, assets, or public funding like that available through CCI to avoid delays in project implementation, or foregoing projects altogether. In these cases, local, state, and federal funding can ensure that projects will continue to move forward.

State law requires DDRDP expenditures funded by CCI to prioritize projects based on criteria pollutant emissions reduction benefits. While environmental credit prices may be sufficient to drive and sustain projects without additional public funds, the absence of these incentives may result in less desirable projects. For example, projects that use a reciprocating engine generator to produce electricity from biogas are often lower cost than other options but result in criteria pollutant impacts, potentially in some of California's most disadvantaged communities.

Similarly, trucking of biomethane to existing interconnection points may be a lower-cost option but may result in increased criteria pollutant emissions and vehicle miles traveled throughout the State. Reducing or eliminating CCI or other public funding for dairy and livestock methane emissions reduction projects may eliminate prioritization of projects that deliver important environmental and public health co-benefits.

### *Alternative Manure Management Projects Are Unlikely to be Implemented Without Incentives*

Alternative manure management practice projects are not eligible to generate environmental credits because it is difficult to quantify methane emissions reductions relative to facility baseline emissions. This results from site-specific project variations that influence methane emissions mitigation. Variability in outcomes is a barrier to develop an offset quantification protocol for alternative manure management practices, so these projects are currently ineligible to generate carbon offset credits under CARB's Cap-and-Trade Program. As a result, financial viability is dependent on public funding, cost savings, and potential sales of value-added manure products like soil amendments and compost. In many cases, these combined savings and revenues are insufficient to offset project development costs, so public investments are critical. Without them, it is unlikely that a large number of projects will be implemented, which may impede the sector's ability to maximize its contribution to the target. These projects also provide important environmental and economic co-benefits through production of high-quality soil amendments, destruction of pathogens, reduction in nitrates and salts that threaten water quality, and production of a product that can be cost effectively transported to replace chemical fertilizer across the State.

### *Additional State Policies and Incentives Can Support Dairy Biomethane Projects*

Long-term policies and incentives can play critical roles in supporting ongoing capture and use of biomethane from the dairy sector to achieve the 2030 target and the State's broader carbon neutrality goals. For example, a funding mechanism that incentivizes the capture of biomethane in California could expand to advance the production and use of biomethane and could provide market certainty to help project developers obtain project financing. While dairy biomethane is currently directed to the transportation fuel market through the LCFS Program, other market-based programs could play a role in directing the biomethane to alternative end uses, including towards industries that are difficult to electrify and otherwise decarbonize.

As described in the 2017 Scoping Plan Update, California must prioritize electrification wherever possible to in order to achieve its GHG emissions reduction goals. The State's electricity sector has already made considerable progress in moving toward zero- or low-GHG emissions generation, but other sectors including transportation, residential, and commercial still offer significant potential to decarbonize using electricity from sources like wind and solar. Some sectors, however, are difficult to electrify so directing dairy and livestock biomethane to these sectors can help decarbonize them, contributing to State carbon neutrality goals. The Scoping Plan Update will discuss additional policies to diversify dairy biomethane use and ensure long-term success of these projects to contribute to State's climate targets.

## Analysis Item 2: Progress Made in Overcoming Technical and Market Barriers to Dairy and Livestock Methane Emissions Reductions Projects

The Strategy identifies barriers to methane emissions reductions measures that the dairy and livestock sector must overcome to achieve the 2030 target. These include technical barriers that impede project development based on various factors including technology limitations, incomplete development, or lack of standardized information. Market barriers impede project development based on factors including cost, availability of financing, environmental credit uncertainty, consumer acceptance, cost-effectiveness, and sector economics. This section will provide a short summary description of how to understand the technical and market barriers in this sector, followed by findings regarding the identified technical barriers and market barriers. Ultimately, the findings support that investment by the State and successful collaborations between agencies, developers, and stakeholders have largely overcome previously significant barriers.

### *Technical Barriers*

Technical barriers impede both manure management methane emissions reduction projects and enteric mitigation strategy development. Specific to manure management, technical barriers impact both anaerobic digestion and alternative manure management projects. As described in the Strategy, technical barriers to anaerobic digestion include difficulties interconnecting with utility electrical grids and natural gas pipeline networks.

Technical barriers to alternative manure management projects result from inconsistent methane emissions reductions across project types and the resultant difficulty with accurately quantifying methane emissions reductions. In some cases, technical barriers may reinforce market barriers, making them even harder to overcome. For example, challenges in quantifying alternative manure management projects impedes the development of offset protocols or other market mechanisms that could improve their financial viability.

***Market Barriers***

Like the technical barriers discussed above, market barriers also impede both anaerobic digestion and alternative manure management projects. As detailed in the Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group, existing market barriers for manure methane reduction projects include project development costs, perceived lack of environmental credit certainty, out-of-State RNG competition, and underdeveloped markets for manure-based products. In addition to competition from out-of-State RNG, electricity and biofuels from California dairy waste faces competition from other sources of in-State renewable electricity such as solar and wind electricity, and competition from other sources of biomethane like landfills. As a result, dairy project developers rely on incentive funding or environmental credit revenues to make projects feasible. However, demand for incentives has consistently outpaced supply, especially for grant funding. Table 7 summarizes the status of progress for each technical and market barrier discussed in this section.

Table 7. Technical and Market Barriers to Implementing Manure Management and Enteric Fermentation Methane Emissions Reductions Projects

| | Technical Barriers | Market Barriers |
|---|---|---|
| **Manure Management** | Alternative manure management projects<br>✗ Inconsistent reductions<br>✗ Difficulty quantifying reductions<br>Anaerobic Digesters<br>✓ Grid and pipeline interconnection<br>✓ Biomethane quality standards | ✓ Project development costs and financing<br>✓ Environmental credit certainty<br>✗ Sector economics<br>✗ Insufficient public funds<br>✗ Undeveloped markets for value-added manure products |
| **Enteric Fermentation** | ✗ Transient effect/rumen adaptation<br>✗ Potential animal health impacts<br>Limited availability<br>✓ Limited products with commercial availability<br>✗ Seasonal products | ? Consumer acceptance<br>? Cost-effectiveness |

✓ = Progress made ✗ = Persistent barrier? = Limited information available

## Finding 2-1: Technical Barriers: Progress Has Been Made on Grid and Pipeline Interconnection and Biomethane Quality Standards, but Other Technical Barriers Remain

### *Technical Barriers to Anaerobic Digestion Projects*

The dairy and livestock sector has made progress in overcoming certain technical barriers of manure methane emissions reductions projects, including access to pipeline networks and utility electrical grids. Project developers and utilities collaborated to understand technological and cost requirements for pipeline and electricity grid interconnection to reduce project development timelines.

Specific to pipeline injection projects, state agencies, utilities, project developers, and suppliers of biomethane upgrading equipment collaborated to identify technology immediately available for dairy operations to upgrade biomethane onsite.[68] Raw biogas from dairy and livestock facilities is mostly comprised of methane and carbon dioxide, with traces of many other constituents including oxygen, nitrogen, hydrogen sulfide, and water. To be injected into the utility pipeline, it must be upgraded, conditioned, and compressed to required pressures. Since the adoption of the Strategy, in Proceeding R.13-02-008, CPUC lowered the minimum heating value required for biomethane injected into natural gas pipelines. Prior to this change, achieving minimum heating value standards was a significant technical challenge and cost barrier for biomethane injection projects. This change resulted in decreased upgrading costs and removed the technical barrier without endangering public health or pipeline integrity.

In 2008, Pacific Gas and Electric Company (PG&E) interconnected the first dairy biomethane pipeline injection project, the first of its kind in California. PG&E continues to allow biomethane producers like dairy and livestock operations to interconnect to the natural gas pipeline system within their coverage area where sufficient capacity and downstream demand within the local pipeline exists. Interconnecting to the PG&E natural gas pipeline network consists of three steps. The first step involves an interconnection screening study which PG&E uses to determine the closest pipeline that can accept a producer's pipeline quality biomethane supply. Step two involves a preliminary engineering study where PG&E reviews the safest, most efficient interconnection route before developing a preliminary cost estimate for the

[68] Online Article. Xebec Enters California Dairy RNG Market with Maas Energy Works. Accessed on December 05, 2019.

interconnection. The final step consists of a detailed engineering study followed by construction of the interconnection.

In 2015, Southern California Gas Company (SoCalGas) began offering the Biogas Conditioning/Upgrading Services Tariff to allow the utility to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment on customer premises. This optional fee service can further assist customers in their coverage area to overcome technical difficulties associated with interconnecting to the natural gas pipeline system. These potential biogas upgrading options help facilities achieve biomethane quality standards necessary for pipeline injection.

PG&E and SoCalGas are also working with dairy biomethane producers to engineer and construct pipeline infrastructure for six dairy biomethane pilot projects pursuant to SB 1383. These projects will help producers, utilities, and the State better understand the technical and economic factors affecting biomethane injection while ensuring and demonstrating successful biomethane delivery into the pipeline network. Additionally, three in-State projects that currently inject biomethane to the utility pipeline system have consistently met SoCalGas biomethane delivery specifications. In 2019, one of these projects completed construction of a digester cluster in Pixley, California and began delivering biomethane to the SoCalGas natural gas pipeline network. While costly, achieving pipeline quality specifications is technically feasible and no longer considered a technical barrier. In fact, in response to CARB's May 2020 webinar on this Analysis, SoCalGas submitted comments clarifying that the utility no longer views achieving pipeline quality specifications for biomethane injection a significant technical barrier.

Project developers and electric utilities have also overcome financial and technical barriers to accessing utility electrical grids. Interconnecting to utility electrical grids requires initial feasibility studies, which can cost several hundred thousand dollars, to outline site-specific technology requirements. Equipment and installation costs for system upgrades can be up to $1 million or more. While the costs and timelines associated with interconnections have not decreased considerably, experience from initial projects has helped to improve understanding of the processes and technical requirements and increased the deployment rate of electricity generation at dairy facilities. Three in-State dairy operations currently have certified LCFS pathways to deliver renewable electricity to the grid for electric vehicle charging with additional facilities—including two solid oxide fuel cell projects under development—that will pursue similar electric vehicle charging pathways to capitalize on potential LCFS credit revenue.

### *Technical Barriers to Alternative Manure Management Projects*

Methane emissions reductions from alternative manure management practices vary substantially based not only on the technology chosen, but also on project-specific implementation variables. For example, a properly operated single stage slope screen solid-liquid separation system might reduce total and volatile solids sent to anaerobic storage by 17 percent. That same separation system operating in exceedance of its throughput capacity may process the same manure stream but with a reduced separation efficiency, allowing manure solids to bypass separation and proceed directly to anaerobic storage, eliminating the benefits intended by the system. Similarly, the composition of manure streams may affect the solid-liquid separation efficiency of the system with some manure streams being more readily separated than others. Such factors can cause considerable variability in solids removal and overall methane emissions reduction effectiveness, making it difficult to quantify reductions accurately and with certainty. In conclusion, alternative manure management practices have great methane emissions reduction potential, but many operational factors can affect their efficiencies, resulting in difficulties to quantify with appropriate certainty the methane emissions reductions benefits. CDFA and CARB have invested in the following research projects consistent with Dairy and Livestock Subgroup 1 Recommendations to better understand the methane emissions reduction potential of various alternative manure management practices:

- **Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California**
  In 2015, CDFA funded this University of California (UC), Davis study to measure the efficiency of various solid-liquid separation technologies. Results showed high variability across technologies resulting from factors including project design, operational capacity, and material throughput, and the associated report recommended additional research, particularly on weeping walls. This study also included an economic analysis to evaluate the cost-effectiveness of methane mitigation strategies on California dairy farms.

- **Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates**
  In 2016, CARB funded this UC Davis research to characterize the physical and chemical properties of manure in California dairy systems.

- **Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology**
  In 2017, CARB funded this UC Davis literature review to assess methane emissions reduction potential of various alternative manure management practices, including solid-liquid separation and weeping walls. Results found all studied technologies had variable performance and the associated report recommended additional research on factors affecting performance of these systems.

- **Benchmarking of Pre- and Post-Alternative Manure Management Program Dairy Emissions and Prediction of Related Long-Term Airshed Effect**
  Between 2016 and 2018, CARB and CDFA collaborated to fund these complementary studies to monitor GHG and air pollutant emissions before and after implementation of various alternative manure management practices at six AMMP-funded dairies. In a separate but complementary effort, CARB installed flux towers to measure methane emissions on three of the six AMMP-funded dairies.

- **Development of the California Dairy Emissions Model**
  In 2019, CARB funded UC Davis to develop a California dairy emissions model to evaluate the effectiveness of potential mitigation strategies and to estimate GHG and other air pollutant emissions from California dairies.

### *Technical Barriers to Enteric Methane Mitigation Strategies*

Enteric strategies, especially feed additives, hold considerable methane mitigation potential from all ruminant species. However, limited commercial availability and seasonal availability of effective feed additives, a lack of long-term effectiveness, and the potential for adverse impacts on animal health for certain products remain persistent technical barriers.

A few methane reducing feed additives with proven long-term effectiveness and no adverse impacts on animal or human health have become commercially available, indicating progress towards overcoming that barrier. However, limited availability of proven strategies remains a barrier for enteric mitigation strategies. For example, the most well-studied potential feed additive, 3-NOP, is expected to become commercially available in the United States in 2024.[69] There is a significant body of evidence to support the effectiveness of 3-NOP in reducing enteric methane emissions by approximately 30 percent. 3-NOP is currently undergoing long-term trials as part of

[69] Mitloehner, F., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

the FDA evaluation and approval process before final approval for commercial distribution.

Grape pomace is another additive that may reduce emissions and may not require FDA approval. However, it is only available in late summer and early fall during grape harvest, limiting its feasibility for year-round emissions reductions. Some novel additives such as seaweed also show methane emissions mitigation potential, but with limited *in vivo* (animal) studies to evaluate their long-term effectiveness and potential impacts on animal health, productivity, and product safety. For example, *Asparagopsis,* a special species of seaweed, shows mitigation potential of up to 90 percent during *in vitro* (non-animal studies using rumen simulation technologies) studies,[70] while *in vivo* studies show a mitigation potential of approximately 50 percent during enteric fermentation.[71] However, this additive is still under development, with many unaddressed technical barriers including the potential risk of elevated bromide residues in milk (a food safety concern), palatability concerns causing decreased feed intake and milk production, and low availability and high cost for the product.

Another persistent technical barrier for enteric methane mitigation strategies is limited long-term information about product effectiveness for most available or emerging options. There are a variety of products in various stages of commercial development that face barriers mentioned above. For example, some additives may impact animal health and productivity. Others may have limited long-term effectiveness due to rumen adaptation leading to rapid additive breakdown.[72] While some additives show great mitigation potential, their long-term impacts on animal health, availability, and cost-effectiveness are not well known. In short, feed additives offer promising potential as a mitigation strategy, but require further research and development before being required for use as part of any CARB regulation. SB 1383 requires that only incentive-based mechanisms are authorized for enteric emissions reductions until CARB, in consultation with CDFA, determines that another mechanism is cost-effective, considering the impact on animal productivity and must be scientifically proven to reduce enteric methane emissions, and that adoption of the enteric

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[70] Machado, L., Magnusson, M., Paul, N., Kinley, R., de Nys, R., Tomkins, N. (2015). Dose-response effects of Asparagopsis taxiformis and Oedogonium sp. on in vitro fermentation and methane production. *Journal of Applied Phycology*, 28(2).

[71] Roque, B. M., Salwen, J. K., Kinley, R., Kebreab, E., (2019). Inclusion of Asparagopsis armata in lactating dairy cows' diet reduces enteric methane emission by over 50 percent. *Journal of Cleaner Production*, 234: 132-138.

[72] Hook, S.E., André -Denis G.W., McBride, B.W. (2010). Methanogens: Methane Producers of the Rumen and Mitigation Strategies. Archaea, 11 pages.

emissions reduction method would not damage animal health, public health, or consumer acceptance.

### *Additional Research to Address Technical Barriers*

The California legislature appropriated $5 million for research grants for FY 2021-22 to measure and verify emissions reductions associated with dairy livestock methane emissions reduction projects. Specifically, the Legislature requires additional research in the following areas:

- Assessment of the cost-effectiveness of various dairy and livestock methane mitigation strategies on a per ton basis including a comparison of projects funded under AMMP and DDRDP
- Assessment of the cost-effectiveness of enteric methane mitigation strategies
- Additional research on value-added manure-based products development
- Measurement of greenhouse gases and criteria pollutants before and after livestock methane reduction projects are implemented

These research projects will further the State's understanding of the effectiveness of anaerobic digestion and alternative manure management projects at achieving methane emissions reductions and environmental co-benefits. In addition, these studies will allow further investigation of the efficacy and cost-effectiveness of enteric strategies, should additional strategies become available.

## Finding 2-2: Market Barriers: The State and Federal Incentive Programs Have Helped Achieve Progress with Project Funding and Incentives

Similar to the technical barriers detailed above, the State, along with others, have made considerable progress in overcoming market barriers to implementing methane emissions reductions projects. Improved understanding of project development costs and significant allocations of CCI funding for manure methane emissions reduction projects have contributed to progress in overcoming barriers related to project funding (Table 8).

Table 8. State Investment in Manure Methane Emissions Reduction Projects

| State Investment Program | Investment ($ million) |
|---|---|
| DDRDP | $196 |
| AMMP | $68 |
| Pilot pipeline construction | $319 |
| Renewable Gas Pipeline Incentive Program | $40 |
| **Total** | **$623** |

This Analysis has already discussed the critical role that market-based programs like Cap-and-Trade and LCFS, RFS, and grant programs like DDRDP and AMMP, have played in driving manure management project development. In addition to those programs, with year-over-year funding to support project development, the Legislature also enacted other initiatives to reduce market barriers for anaerobic digestion projects. Through SB 1383, the Legislature directed CPUC, along with CARB and CDFA, to select six pilot projects to demonstrate biomethane injection into the common carrier pipeline network. This pilot program committed $319 million in rate-recoverable funding to 45 dairies for pipeline infrastructure and operational expenses over 20 years with no private match funding requirement.[73] These projects will provide valuable information on pipeline interconnection processes and the associated costs.

CPUC also administers BioMAT, which provides long-term power purchase agreements with a guaranteed price to projects that generate onsite electricity from certain biogenic feedstock and deliver that electricity to the grid. This market program allows three utilities (Pacific Gas and Electric Co., San Diego Gas & Electric Co., and Southern California Edison) to offer favorable rates to onsite generation projects using a market adjusting mechanism that periodically increases the rate until there are enough market participants. BioMAT has funded two projects for a cumulative total of $8 million, with eight additional projects pending. To date, dairy electricity generation projects have filled nearly 19 megawatts (MW) of the 90 MW available. Another program administered by CPUC is the Renewable Gas Pipeline Interconnection Incentive Program, which provides cost share for dairy biomethane pipeline injection projects. The Legislature appropriated $40 million for pipeline interconnection projects, with up to $3 million in infrastructure cost share available for single-dairy projects, and up to $5 million for dairy cluster projects. Although these programs predate SB 1383, both have seen increased interest since it was enacted.

These incentive programs have been critical to funding the upfront costs of anaerobic digesters, and have also been consistently oversubscribed, which shows an unmet need for additional local, state, and federal investment. However, the availability of incentives coupled with environmental credit revenue has led to increased private investment. Private equity firms and companies have invested in anaerobic digesters, creating additional opportunities for project developers and financers. Increased private funding may result in projects that are financially solvent without upfront incentives, but these funding sources are limited. Sustained environmental credit

[73] California Public Utilities Commission. (December 3, 2018). CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Projects to Demonstrate Connection to Gas Pipelines.

revenue can further reduce risk to lenders and deliver quicker returns on investments, making these projects increasingly attractive to private capital.

One important consideration about the role of public funding is its ability to prioritize multiple benefits. For instance, private capital will pursue biomethane or electricity options that minimize costs and maximize revenue available through environmental credits. In contrast, the State can require funded projects to meet multiple goals. For example, CDFA prioritizes DDRDP projects that minimize environmental impacts including NOx and air pollutants and maximize the environmental co-benefits and community benefits as required by the Legislature when it passed SB 859 (Chapter 368, Statutes of 2016). Implementation of SB 859 has resulted in widespread implementation of pipeline injection projects due to their lower air quality impact compared to relatively lower-cost onsite combustion or trucking projects.

Alternative manure management practices and enteric methane mitigation strategies have not seen similar progress in project funding; without additional local, State, and federal funding, these project types are unlikely to move forward.

## Finding 2-3: Market Barrier: Clarity from the State Has Improved Environmental Credit Certainty

California's Cap-and-Trade Program and LCFS Program, and the federal RFS Program, are the primary policy and programmatic mechanisms that provide environmental credit revenue for dairy digesters. To improve market certainty of the Cap-and-Trade Program and LCFS Program for dairy digesters, CARB developed the following two documents:

- Credit Generation for Reduction of Methane Emissions from Manure Management Operations helps project developers better understand potential impact to environmental credit generation that a methane emissions reduction regulation may have, to provide greater market certainty.

- The SB 1383 Pilot Financial Mechanism Paper describes a potential pilot financial mechanism that, if implemented, could improve stability and certainty around LCFS credits generated from anaerobic digestion at dairy operations. The white paper describes two potential approaches—put options and contracts for differences—to ensure that participating facilities can receive a set minimum LCFS credit price. Increasing revenue certainty helps project developers access private financing, potentially reducing or eliminating the need for long-term public support. For the mechanism to be implemented, however, it would need an administrator and initial funding. The white paper notes that CARB should not administer this program because of a conflict of interest as the LCFS Program administrator.

## Finding 2-4: Market Barriers Remain for Value-Added Manure Products, Alternative Manure Management Projects, and Enteric Methane Mitigation Strategies

Despite progress, persistent market barriers for alternative manure management projects and enteric methane mitigation strategies create an enduring need for funding to support these methane emissions reduction strategies.

### *Market Barriers for Value-Added Manure Products*

Underdeveloped markets for value-added manure products is a persistent market barrier that, if addressed, could improve the financial viability of manure management projects and provide a variety of environmental co-benefits. Most alternative manure management practices produce compost that could be further commodified to provide an additional revenue stream for dairy operators. Improved markets for such products may also drive additional upstream or downstream GHG emissions reductions. For example, manure compost typically contains fewer contaminants and has higher nutrient content than municipal green waste. Similarly, dairy-based organic fertilizers avoid the upstream GHG emissions resulting from manufacture and distribution of synthetic, fossil-based fertilizers. As a result, value-added manure products can potentially provide an important revenue stream to dairy and livestock operations that could reduce reliance on public funding.

Additionally, these products can provide important environmental co-benefits, including soil health, water retention, and potential displacement of petrochemical fertilizers. Market maturation would offer more opportunity to export nutrient-rich manure solids and reduce potential for water quality impacts from land application of manure. These benefits may be especially important in the San Joaquin Valley, where representative groundwater monitoring shows widespread water quality impacts.[74]

Despite considerable potential benefit to producers and consumers, there is limited information available about the demand for value-added manure products or the quantity that can be cost effectively delivered to the market. To help overcome market barriers and facilitate value-added manure products market development, CDFA is

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[74] Shrestha, A. & Luo, W. (2017). An assessment of groundwater contamination in Central Valley aquifer, California using geodetector method. *Annals of GIS*, 23(3), 149-166.

planning to convene a focused working group to address these obstacles and improve financial viability of alternative manure management projects.

***Market Barriers to Alternative Manure Management Projects***

In many cases, adopting alternative manure management practices at dairies may not be cost-effective due to the lack of revenue streams to generate attractive rates of return to farmers and developers. Additionally, many of the dairies that implement these practices may not have the have the resources to diversify their operations to take advantage of new or expanded market opportunities. In the absence of public funding, these operations—often smaller and less able to capitalize on economies of scale—will need to rely on cost savings and revenue from the sale of value-added manure products (e.g., compost and soil amendment). However, the limited financial benefits of these projects are often insufficient to offset project costs. Additionally, ineligibility for environmental credits and underdeveloped markets for value-added manure products present additional market barriers. As a result, the availability of debt financing is limited.

***Market Barriers to Enteric Methane Mitigation Strategies***

Limited information is available for a comprehensive analysis of market barriers for enteric mitigation strategies, though market barriers may arise as options become available. However, to be viable, the market requires potential products to gain consumer acceptance and be cost-effective. SB 1383 requires cost-effectiveness of products, among other requirements, prior to requiring their use. Additives that fail to meet these requirements are unlikely to be adopted as effective enteric methane mitigation strategies.

## Next Steps

Moving forward, the dairy and livestock sector must still achieve considerable methane emissions reductions to meet the 2030 target. Achieving the target will require careful consideration of potential methane emissions reductions strategies and coordination with other agencies, the dairy and livestock sector, and the public, including environmental justice and disadvantaged communities. Implemented strategies must not only reduce methane emissions from the sector sufficient to achieve the 2030 target but should also be consistent (to the extent feasible) with other State objectives. These objectives include reduced impacts to air and water quality, improved soil health, reduced impacts to environmental justice communities, and maximized GHG emissions reductions while minimizing emissions leakage. This will require coordinated action between the State and the dairy and livestock sector to overcome barriers to implementing proven methane emissions reduction projects and emerging mitigation options, especially for enteric fermentation. Improved accuracy in tracking and quantifying methane emissions reductions achieved by operational manure management projects or expected from future projects—especially alternative manure management projects and emerging enteric methane reducing feed additives—is also critical to evaluating progress toward the 2030 target. These improvements will help identify effective incentives and policies in the near-term and will aid in the design of potential regulations should that be necessary for achieving the 2030 target. The 2022 Scoping Plan Update will further assess and describe the role that the dairy and livestock sector can play to help achieve carbon neutrality.

CARB staff will continue to monitor the dairy and livestock sector's methane emissions reductions progress and refine its understanding of emissions sources, emissions reduction potential, and the achievements of incentives. CARB will continue to research additional technology options and management practices that can achieve methane emissions reductions, as well as research the effectiveness of practices used today. CARB will consider potential options to improve quantification of methane emissions reductions from manure management projects as well as ways to refine GHG emissions accounting for the sector. In order to comply with the statutory direction, CARB will consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in the statute are met. These next steps are described in greater detail below.

## Continue Tracking Progress of Methane Emissions Reduction Projects and Funding

The State's appropriation of $289 million in CCI funds for manure methane emissions reductions to date has resulted in 233 dairy manure management projects that will achieve an estimated 2.0 $MMTCO_2e$ in annual reductions by 2022. This funding delivers some of the most cost-effective SLCP emissions reductions to date. CARB staff will continue to track the availability of local, State, and federal incentive funding, the progress of existing projects, and future projects implemented using both public and private funds. Additionally, CARB staff will continue to monitor market developments for value added manure products, and CDFA will convene a working group to reduce market barriers and improve the financial viability of alternative manure management projects.

## Continue Tracking Manure Management Methane Emissions Reduction Options

CARB staff will track advancements in manure methane emissions reductions. Specifically, staff will continue to monitor the results of ongoing research including the monitoring emissions at AMMP project sites pre- and post-implementation, CPUC pilot pipeline infrastructure projects, methane emissions flux monitoring, literature reviews, and the development of a dairy emissions model to better understand changes from manure management methane emissions reduction projects. CARB, in collaboration with CDFA, will also continue to evaluate the potential for additional alternative manure management practices.

## Continue Tracking Enteric Methane Emissions Reduction Options

There are limited commercially available animal feed for mitigating enteric methane emissions reductions additives in the United States. Some regions, including Brazil, Chile, and Europe have recently approved the use of 3-NOP.[75,76] CARB staff will continue to track the progress of these enteric methane emissions mitigation strategies, analyze their cost-effectiveness, and assess consumer acceptance.

## Address GHG Emission Inventory Challenges

In addition to tracking enteric and manure methane emissions reductions options, CARB staff is evaluating options to improve the accuracy of the annual GHG Emission Inventory. Gathering operational or "activity data"[77] from facilities within the sector is an important first step to refining inventory models and associated assumptions to be more California-specific. These refinements would improve GHG Emission Inventory accuracy and inform incentive planning and regulatory development efforts.

Detailed facility activity data on the parameters that affect methane emissions should be collected annually. Specific data may include animal breed, population, production stage, diet composition, animal housing type, and the manure collection rate, storage conditions and length, treatment methods, and land application rates of manure. A more accurate accounting of these parameters can help assess methane mitigation strategies and calibrate emission models.

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[75] https://www.bloomberg.com/news/articles/2021-09-09/world-s-top-beef-supplier-approves-methane-busting-cow-feed

[76] https://www.dsm.com/corporate/news/news-archive/2022/dsm-receives-eu-approval-Bovaer.html

[77] Activity data refers to important factors that can impact emissions from dairy and livestock operations. Some example factors include animal population size, breed, age, lactation status, diet, and type of manure management.

CARB recommends a collaborative effort including public agencies and industry to gather activity data from dairy and livestock operations. Specifically, it may evaluate leveraging or modifying existing reporting structures like annual water quality reports to gather additional activity data from the sector. This approach may increase the likelihood of a high response rate, reduce resources needed to develop a new reporting structure, and reduce the reporting burdens to dairy and livestock operations. A voluntary survey of the sector could also provide useful activity data if a new or modified reporting structure is infeasible.

If these efforts are infeasible or are unsuccessful, a recordkeeping and reporting regulation developed pursuant to SB 1383[78] could provide a mechanism to obtain the necessary activity data. Reported information would be used to improve inventory accuracy, evaluate methane emissions reduction progress, and inform design of potential emissions reduction regulations, should that be necessary.

[78] Section 39730.7(h).

# ATTACHMENT AA

CALIFORNIA
AIR RESOURCES BOARD

December 2022

# 2022 Scoping Plan for Achieving Carbon Neutrality

CARB's mission is to promote and protect public health, welfare, and ecological resources through effective reduction of air pollutants while recognizing and considering effects on the economy. CARB is the lead agency for climate change programs and oversees all air pollution control efforts in California to attain and maintain health-based air quality standards.

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# Abbreviations

| | |
|---|---|
| °F | Fahrenheit |
| °C | Celsius |
| AB | Assembly Bill |
| AQMD | Air Quality Management District |
| AR5 | IPCC Fifth Assessment Report |
| BECCS | bioenergy with carbon capture and storage |
| CAISO | California Independent System Operator |
| CalEPA | California Environmental Protection Agency |
| CalGEM | California Geologic Energy Management Division |
| CalSTA | California State Transportation Agency |
| CAP | climate action plan |
| CARB | California Air Resources Board |
| CCR | California Code of Regulations |
| CCS | carbon capture and sequestration |
| CCUS | carbon capture, utilization, and storage |
| CDFA | California Department of Food and Agriculture |
| CDPH | California Department of Public Health |
| CDR | carbon dioxide removal |
| CE | common era |
| CEC | California Energy Commission |
| CEQA | California Environmental Quality Act |
| CES | CalEnviroScreen |
| $CH_4$ | methane |
| CMAQ | Community Multiscale Air Quality |
| CNRA | California Natural Resources Agency |
| $CO_2$ | carbon dioxide |
| COPD | chronic obstructive pulmonary disease |

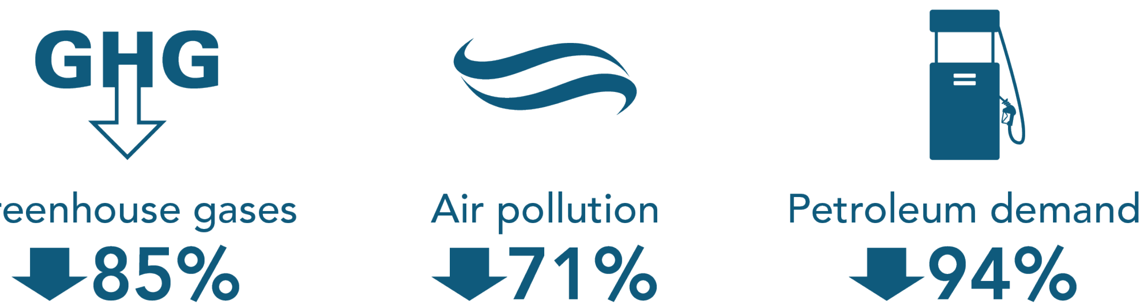
| | |
|---|---|
| CORE | Clean Off-Road Equipment |
| CPUC | California Public Utilities Commission |
| CVM | Climate Vulnerability Metric |
| DAC | direct air capture |
| DPR | Department of Pesticide Regulation |
| Draft EA | Draft Environmental Analysis for this Scoping Plan |
| EA | Environmental Analysis |
| ED | emergency department |
| EIA | U.S. Energy Information Administration |
| EJ | environmental justice |
| EJ Advisory Committee | Environmental Justice Advisory Committee |
| EO | executive order |
| EV | electric vehicle |
| F-gas | fluorinated gas |
| FCEV | fuel cell electric vehicle |
| GCF | Governors' Climate and Forests Task Force |
| GDP | gross domestic product |
| GHG | greenhouse gas |
| GSP | gross state product |
| GW | gigawatt |
| GWh | gigawatt-hour |
| GWP | global warming potential |
| HDV | heavy-duty vehicle |
| HD ZEV | heavy-duty zero-emission vehicle |
| HFC | hydrofluorocarbon |
| IBank | Infrastructure and Economic Development Bank |
| ICE | internal combustion engine |
| IPCC | Intergovernmental Panel on Climate Change |

| | |
|---|---|
| IPT | incidence-per-ton |
| IWG | Interagency Working Group |
| LCFS | low-carbon fuel standard |
| LDV | light-duty vehicle |
| MDV | medium-duty vehicle |
| MMT | million metric tons |
| $MMTCO_2e$ | million metric tons of carbon dioxide equivalent |
| MOU | memorandum of understanding |
| MRR | Mandatory Reporting of GHG Emissions |
| $MTCO_2e$ | metric tons of carbon dioxide equivalent |
| MW | megawatt |
| $N_2O$ | nitrous oxide |
| NEMS | National Energy Systems Model |
| $NF_3$ | nitrogen trifluoride |
| NOAA | National Oceanic and Atmospheric Administration |
| NOx | nitrogen oxides |
| NRDC | National Resources Defense Council |
| NWL | Natural and Working Lands |
| OEHHA | Office of Environmental Health Hazard Assessment |
| OGV | Ocean-Going Vessel |
| OPR | Governor's Office of Planning and Research |
| OTC | once-through cooled |
| PFC | perfluorocarbon |
| PHMSA | Pipelines and Hazardous Materials Safety Administration |
| PM | particulate matter |
| $PM_{2.5}$ | fine particulate matter |
| PPP | public-private partnership |
| RFS | renewable fuel standard |

| | |
|---|---|
| ROG | reactive organic gases |
| RPS | Renewables Portfolio Standard |
| SB | Senate Bill |
| $SC\text{-}CH_4$ | social cost of methane |
| $SC\text{-}CO_2$ | social cost of carbon |
| SC-GHG | social cost of greenhouse gases |
| $SC\text{-}N_2O$ | social cost of nitrous oxide |
| $SF_6$ | sulfur hexafluoride |
| SGIP | Self-Generation Incentive Program |
| SLCP | short-lived climate pollutant |
| TSD | Technical Support Document |
| UC | University of California |
| UCLA | University of California, Los Angeles |
| UNFCCC | United Nations Framework Convention on Climate Change |
| U.S. EPA | United States Environmental Protection Agency |
| VMT | vehicle miles traveled |
| WUI | wildland-urban interface |
| ZEV | zero-emission vehicle |

# Executive Summary

This Scoping Plan lays out the sector-by-sector roadmap for California, the world's fifth[1] largest economy, to achieve carbon neutrality by 2045 or earlier, outlining a technologically feasible, cost-effective, and equity-focused path to achieve the state's climate target. This is a challenging but necessary goal to minimize the impacts of climate change. There have been three previous Scoping Plans. Previous plans have focused on specific greenhouse gas (GHG) reduction targets for our industrial, energy, and transportation sectors—first to meet 1990 levels by 2020, then to meet the more aggressive target of 40 percent below 1990 levels by 2030. This plan, addressing recent legislation and direction from Governor Newsom, extends and expands upon these earlier plans with a target of reducing anthropogenic emissions to 85 percent below 1990 levels by 2045. This plan also takes the unprecedented step of adding carbon neutrality as a science-based guide and touchstone for California's climate work. The plan outlines how carbon neutrality can be achieved by taking bold steps to reduce GHGs to meet the anthropogenic emissions target and by expanding actions to capture and store carbon through the state's natural and working lands and using a variety of mechanical approaches.




What this means for California is an ambitious and aggressive approach to decarbonize every sector of the economy, setting us on course for a more equitable and sustainable future in the face of humanity's greatest existential threat, and ensuring that those who benefit from this transformation include communities hardest hit by climate impacts and the ongoing pollution from the use of fossil fuels. The combustion of fossil fuels has polluted our air—particularly in low-income communities and communities of color—for far too long and is the root cause of climate change. This Scoping Plan helps us chart the path to a future where race and class are no longer predictors of disproportionate burdens from harmful air pollution and climate impacts.

The major element of this unprecedented transformation is the aggressive reduction of fossil fuels wherever they are currently used in California, building on and accelerating carbon reduction programs that have been in place for a decade and a half. That means rapidly moving to zero-emission transportation; electrifying the cars, buses, trains, and trucks that now constitute California's single largest source of planet-warming pollution. It also means phasing out the use of fossil gas used for heating our homes and buildings. It means clamping down on chemicals and refrigerants that are thousands of times more powerful at trapping heat than carbon dioxide ($CO_2$). It means providing our communities with sustainable options for walking, biking, and public transit to reduce reliance on cars and their associated expenses. It means continuing to build out the solar arrays, wind turbine capacity, and other resources that provide clean, renewable energy to displace fossil-fuel fired electrical generation. It also means scaling up new options such as renewable hydrogen for hard-to-electrify end uses and biomethane where needed. Successfully achieving the outcomes called for in this Scoping Plan would reduce demand for liquid petroleum by 94 percent

1 In October 2022, California was poised to become the world's fourth largest economy.

and total fossil fuel by 86 percent in 2045 relative to 2022.[2] Despite these world-leading efforts, some amount of residual emissions will remain from hard-to-abate industries such as cement, internal combustion vehicles still on the road, and other sources of GHGs, including high global warming chemicals used as refrigerants.

The plan addresses these remaining emissions by re-envisioning our natural and working lands—forests, shrublands/chaparral, croplands, wetlands, and other lands—to ensure they play as robust a role as possible in incorporating and storing more carbon in the trees, plants, soil, and wetlands that cover 90 percent of the state's 105 million acres while also thriving as a healthy ecosystem. Modeling indicates that natural and working lands will not, on their own, provide enough sequestration and storage to address the residual emissions. For that reason, it is necessary to research, develop, and deploy additional methods of capturing $CO_2$ that include pulling it from the smokestacks of facilities, or drawing it out of the atmosphere itself and then safely and permanently utilizing and storing it, as called for in recent legislation. Carbon removal also will be necessary to achieve net negative emissions to address historical GHGs already in the atmosphere.

This is a plan that aims to shatter the carbon status quo and take action to achieve a vision of California with a cleaner, more sustainable environment and thriving economy for our children. This ambitious plan will serve as a model for other partners around the world as they consider how to make their transition. As we have so often in the past, California can continue to serve as a leader in innovation that has produced not only the fifth largest economy on the planet, but ultimately one of the most energy-efficient economies, with a track record of demonstrating the ability to decouple economic growth from carbon pollution. This plan also builds upon current and previous environmental justice efforts to integrate environmental justice directly into the plan, to ensure that all communities can reap the benefits of this transformational plan. Specifically, this plan identifies a path to keep California on track to meet its SB 32 GHG reduction target of at least 40 percent below 1990 emissions by 2030.

2 See *CARB's energy demand reductions*.

- Identifies a technologically feasible, cost-effective path to achieve carbon neutrality by 2045 and a reduction in anthropogenic emissions by 85 percent below 1990 levels.
- Focuses on strategies for reducing California's dependency on petroleum to provide consumers with clean energy options that address climate change, improve air quality, and support economic growth and clean sector jobs.
- Integrates equity and protecting California's most impacted communities as driving principles throughout the document.
- Incorporates the contribution of natural and working lands (NWL) to the state's GHG emissions, as well as their role in achieving carbon neutrality.
- Relies on the most up-to-date science, including the need to deploy all viable tools to address the existential threat that climate change presents, including carbon capture and sequestration, as well as direct air capture.
- Evaluates the substantial health and economic benefits of taking action.
- Identifies key implementation actions to ensure success.

The path forward is informed by robust science. The recent Sixth Assessment Report (AR6) of the Intergovernmental Panel on Climate Change (IPCC) summarizes the latest scientific consensus on climate change. It finds that atmospheric concentrations of $CO_2$ have increased by 50 percent since the industrial revolution and continue to increase at a rate of two parts per million each year.[3] By the 2030s, and no later than 2040, the world will exceed 1.5°C warming unless there is drastic action. While every tenth of a degree matters — every incremental increase in warming brings additional negative impacts — climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2°C warming, compared to 1.5°C.[4] For example, at 1.5°C of global warming, we would experience increasing heat waves, longer warm seasons, and shorter cold seasons, but at 2°C of global warming, heat extremes would more often reach critical tolerance thresholds for human health and agriculture.[5] We are already seeing unprecedented climate change impacts, such as continued sea level rise, that are "irreversible" for centuries to millennia, and we are dangerously close to hitting 1.5°C in the near term.[6] To avoid climate catastrophe and remain below 1.5°C with limited or no overshoot of that threshold, global net anthropogenic $CO_2$ emissions need to reach net zero by 2050.

3 *IPCC. 2021. Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. In Press.*

4 *IPCC. 2018. Global Warming of 1.5°C. World Meteorological Organization. Geneva, Switzerland. 32 pp.*

5 *IPCC. 2021. Climate change widespread, rapid, and intensifying – IPCC. August.*

6 *United Nations. 2021. IPCC report: 'Code red' for human driven global heating, warns UN chief. August 9.*

It has been 16 years since the Global Warming Solutions Act of 2006 was passed and signed into law. In 2017, the second update to the Assembly Bill (AB) 32 Climate Change Scoping Plan[7] (2017 Scoping Plan) laid out a cost-effective and technologically feasible path to achieve the 2030 GHG reduction target. At the time, many characterized the plan and the AB 32 target as unachievable, citing that it would lead to massive business and job loss, and excessive costs. Those predictions proved to be incorrect as California achieved its AB 32 target years ahead of schedule, all the while growing our economy, with the state distinguishing itself as a hub for green technology investment. This Scoping Plan draws on a decade and a half of proven successes and additional new approaches to provide a balanced and aggressive course of effective actions to achieve carbon neutrality in 2045, if not before, in addition to the 2030 goal.

California's economy is projected to grow vigorously in the coming years and decades. In 2045, under a Reference Scenario, the gross state product would be $5.1 trillion, nearly $2 trillion more than in 2021, and allow growth that would add hundreds of thousands of jobs. Under the Scoping Plan scenario, impacts to economic and job growth would be negligible in both 2035 and 2045, while delivering $199 billion of benefits in the form of reduced hospitalizations, asthma cases, and lost work and school days due to the cleaner air supported by this plan. This should come as no surprise given the tremendous growth of California's economy since the Great Recession of 2007–2009, even as the state has taken drastic measures to lower emissions. As noted, the savings associated with ambitious climate action are extensive, both in terms of avoided climate impacts and health costs. As described in Chapter 1, the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years[8] without robust action. Similarly, the costs of delayed or insufficient climate action could cost the U.S. upwards of $14.5 trillion over the next 50 years.[9] We can either take action now or pay the cost of inaction, both now and later.

Grows CA's economy
to $5.1 trillion by 2045

New jobs
↑ 4 million

Health costs
↓ $200 billion

We cannot take on this unprecedented challenge alone. Collaboration with the federal government, other U.S. states, and other jurisdictions around the world will continue to be fundamental for California to succeed in achieving its climate targets, especially as the pace of our efforts increases in the coming years. We believe this collaboration and coordination also creates a race to the top, encouraging and enabling other jurisdictions to achieve climate and air quality goals as well, and often providing lessons for national action.

One example of fruitful collaboration is California's longstanding vehicle emissions standards programs, which have repeatedly been freely adopted by other states, consistent with the federal Clean Air Act. California's programs frequently pioneer more rigorous standards or new technologies—such as the now-standard catalytic converter and the rules that led directly to the nation-leading numbers of zero-emission vehicles on our roads today. From initial standards for cars

7 *CARB. 2017. California's 2017 Climate Change Scoping Plan.*

8 *Alwis, D. D., and V. S. Limaye. No date. The Costs of Inaction: The Economic Burden of Fossil Fuels and Climate Change on Health in the United States. NRDC, The Medical Society Consortium on Climate and Health, and WHPCA.*

9 *Deloitte. 2022. The Turning Point: A New Economic Climate in the United States.*

and trucks decades ago to the world-leading Advanced Clean Trucks program currently helping to electrify heavy-duty vehicles, this partnership continues to offer regulatory options and spread innovative technologies. A major example of future work is the Advanced Clean Cars II program, which lays out California's legally binding path to achieving 100 percent zero emission vehicle (ZEV) sales in 2035.[10] The California Air Resources Board (CARB) continues to work closely with many other states that also see zero-emission vehicles as critical to their climate and public health goals and expects many states to choose to adopt this regulation as well. This partnership with other states also creates market certainty for automakers, which in turn helps to ensure that California consumers have access to a variety of ZEVs at multiple price points.

## The Scoping Plan Process

Four scenarios were extensively modeled to develop this Scoping Plan, with the objective of informing the most viable path to remain on track to achieve our 2030 GHG reduction target: a reduction in anthropogenic emissions by 85% below 1990 levels and carbon neutrality by 2045. All four have their merits and are informed by stakeholder input. The scenario ultimately chosen as the basis of this Scoping Plan is the alternative that most closely aligns with existing statute and Executive Orders. It was selected because it best achieves the balance of cost-effectiveness, health benefits, and technological feasibility.

For the first time, this Scoping Plan includes modeling and quantification of GHG emissions and carbon sequestration in natural and working lands (NWL). To date, the focus has been only on reducing the emissions of GHGs from our transportation, energy, and industrial sectors. The state's 2020 and 2030 GHG reductions targets only include these sources, as they are the primary drivers of climate change and disproportionate harmful air pollution in our vulnerable communities. This Scoping Plan, through the lens of carbon neutrality, expands the scope to more meaningfully consider how our NWL contribute to our long-term climate goals. For the first time, new and cutting-edge modeling tools allow us to estimate the quantitative ability of our forests and other landscapes to remove and store carbon under different scenarios. These cutting-edge tools were developed through a stakeholder process and in coordination with other agencies for the purpose of this update and will continue to be refined over time and made available to others seeking to do similar work.

10 *Executive Department. State of California. Executive Order N-79-20.*

As recent data and Scoping Plan modeling shows, our NWL also can act as a source of emissions, principally in the form of wildfires. California's forests are experiencing a deadly combination of drought and heat combined with a century of misguided fire suppression management. Scoping Plan modeling shows that, at this time and until our forests reach a balance through appropriate treatments, California's NWL will act as a net source of emissions, not a sink. As such, the Scoping Plan includes policy direction and actions intended to quickly move the sector toward being a net sink and a more natural state, where wildfires will continue to be an important part of the healthy forest cycle but not at the intensity and frequency observed in recent years.

Development of this Scoping Plan also includes careful consideration of, and coordination with, other state agencies, consistent with Governor Gavin Newsom's whole-of-government approach to tackling climate change. State agency plans and regulations, including the SB 100 Joint Agency Report,[11] State Implementation Plan, Climate Action Plan for Transportation Infrastructure,[12] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[13,14,15] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[16] CARB's Achieving Carbon Neutrality Report,[17] Climate Smart Lands Strategy,[18] Natural Working Land Implementation Plan,[19] and the California Climate Insurance Report: Protecting Communities, Preserving Nature, and Building Resiliency,[20] among others, provided critical inputs and data points for this plan. This Scoping Plan is the product of work by multiple agencies across the Administration, including dozens of public workshops and years of rigorous analysis and economic modeling by California's leading institutions. This cooperation on planning lays the foundation for even closer coordination among and between state agencies to put the plan into effect.

The plan is also the product of tireless efforts of, and recommendations from, the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee). The EJ Advisory Committee, created by statute, plays a critical role to inform the development of each Scoping Plan and helps to ensure environmental justice is integrated throughout the plan. CARB reconvened the EJ Advisory Committee in early 2021 to advise on the development of this Scoping Plan. In their advisory role, the EJ Advisory Committee has worked together to provide inputs to CARB to inform the development of scenarios and the associated modeling. And in April 2022, the EJ Advisory Committee provided draft preliminary recommendations in advance of the Draft 2022 Scoping Plan to help ensure the draft plan meaningfully addresses environmental justice. The CARB Board and EJ Advisory Committee held a joint board hearing on September 1, 2022, where the EJ Advisory Committee presented their final recommendations on the Scoping Plan. Over five dozen of the recommendations are reflected in the Scoping Plan. Going forward, as this plan is ultimately acted on by the Board, ongoing input from the EJ Advisory Committee will be essential to address environmental justice and achieve the ambitious vision outlined in the plan throughout its implementation in the coming years.

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11 *California Public Utilities Commission (CPUC), California Energy Commission (CEC), and CARB. 2021. SB 100 Joint Agency Report.*

12 *California State Transportation Agency (CalSTA). 2021. Climate Action Plan for Transportation Infrastructure.*

13 *California Environmental Protection Agency (CalEPA). 2021. Carbon Neutrality Studies.*

14 *Brown, A. L., et. al. 2021. Driving California's Transportation Emissions to Zero. University of California Institute of Transportation Studies.*

15 *Deschenes, O. 2021. Enhancing equity while eliminating emissions in California's supply of transportation fuels. University of California Santa Barbara.*

16 *CARB. Short-Lived Climate Pollutants.*

17 *Energy and Environmental Economics, Inc. 2020. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board. October.*

18 *California Natural Resources Agency (CNRA). 2021. Draft Climate Smart Lands Strategy.*

19 *CARB. 2019. Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.*

20 *California Department of Insurance. 2021. Protecting Communities, Preserving Nature, and Building Resiliency.*

Importantly, per legislative direction, the Scoping Plan development includes modeling and analyses of emissions, economics, air quality, health, jobs, and public health. This work is important to inform the discussion around trade-offs and how to balance the various legislative direction in identifying a path to achieve the state's climate goals. The technical work serves as a backdrop to what this means to Californian's daily lives—to how they will work, play, and live as we act to eliminate fossil fuel combustion and achieve the many public health and environmental benefits that will result from that action.

## Ensuring Equity and Affordability

The state has a long history of public health and environmental protection. However racist and discriminatory practices such as redlining have resulted in low-income communities and communities of color being disproportionately exposed to health hazards and pollution burdens.[21] These communities are often located adjacent to major roadways and large stationary sources that not only emit GHGs, but also harmful localized air pollution. The plan delivers on the promise to transform the way we move, live, and work by nearly eliminating our dependence on fossil fuels. It includes effective actions to move with all possible speed to clean energy, zero-emission cars and trucks, energy-efficient homes, sustainable agriculture, and resilient NWL. And it prioritizes working with the communities most impacted to ensure that these strategies address their needs.

An important part of our equity consideration is ensuring the transition to a zero-emission economy is affordable and accessible, and that it uplifts disadvantaged, low-income communities and communities of color. Some aspects of the transition will have associated costs (e.g., escalating efforts to retrofit existing homes and businesses to support electric appliances and vehicles and increased costs of insurance). The state must ensure that these costs do not disproportionately burden consumers. In addition, the state has an important role to play in providing financial incentives, especially to low-income consumers, to allow for uptake of clean technologies. The Department of Community Services and Development's Low Income Weatherization Program is a prime example of this approach, enabling low-income Californians to be part of the zero-emission transition, all while lowering energy bills. The program provides low-income households with solar

21 *CalEPA. 2021. Pollution and Prejudice: Redlining and Environmental Injustice in California. August 16.*

photovoltaic systems and energy efficiency upgrades at no cost to residents, helping cushion the impact of climate change on vulnerable communities.

With this Scoping Plan, the state also adds another tool to help identify and close climate change impact gaps that will emerge over time. As California invests in climate mitigation and adaptation, it is essential to understand the relative impact of climate change across the state's diverse communities. We know not all communities are equally resilient in the face of climate impacts due to persisting health and opportunity gaps. We also know that a global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare.

## Energy and Technology Transitions

To support the transformation needed, we must build the clean energy production and distribution infrastructure for a carbon-neutral future. The solution will have to include transitioning existing energy production and transmission infrastructure to produce zero-carbon electricity and hydrogen, and utilizing biogas resulting from wildfire management or landfill and dairy operations, among other substitutes. In almost all sectors, electrification will play an important role. That means that the grid will need to grow at unprecedented rates and ensure reliability, affordability, and resiliency through the next two decades and beyond. It also means we need to keep all options on the table, as it will take time to fully grow the electricity grid to be the backbone for a decarbonized economy. We also know that electrification is not possible in all situations. As such, this plan systematically evaluates and identifies feasible clean energy and technology options that will bring both near-term air quality benefits and deliver on longer-term climate goals.


**4x**
solar & wind generation

**1,700x**
renewable hydrogen

**100%**
ZEV sales by 2035

This transition will not happen overnight. It will take time and planning to ensure a smooth transition of existing energy infrastructure and deployment of new clean technology. And while this Scoping Plan has the longest planning horizon of any Scoping Plan to date, this 25-year horizon is still relatively short in terms of transforming California's economy. We must avoid making choices that will lead to stranded assets and incorporate new technologies that emerge over time. Importantly, given the pace at which we must transition away from fossil fuels, we absolutely must identify and address market and implementation barriers to be successful. The scale of transition includes adding four times the solar and wind capacity by 2045 and about 1,700 times the amount of current hydrogen supply.

As we transition our energy systems, we must also rapidly deploy the clean technologies that rely on a decarbonized grid. As called for in Executive Order N-79-20, all new passenger vehicles sold in California will be zero-emission by 2035, and all other fleets will have transitioned to zero-emission as fully possible by 2045. This means the percentage of fossil fuel combustion vehicles will continue to rapidly decrease, becoming a fading vision of the past. Successful implementation of this Executive

Order (EO) and other zero-emission priorities will have to be attractive to consumers. As an example, electric and hydrogen transportation refueling must be readily accessible, and active transportation and clean transit options must be cheaper and more convenient than driving.

## Cost-Effective Solutions Available Today

Ultimately, to achieve our climate goals, urgent efforts are needed to slash GHG emissions. Fortunately, cost-effective solutions are available to do so in many cases. In short, this plan relies on existing technologies—it does not require major technological breakthroughs that are highly uncertain.

For example, targeted action to reduce methane emissions can be achieved at low or negative cost, and with significant near-term climate and public health benefits. In many cases, renewable energy and energy storage are cheaper than polluting alternatives, and are already firmly part of our business-as-usual approach; modeling related to the most recent integrated resource planning process at the California Public Utilities Commission (CPUC) has shown that scenarios associated with the best emissions outcomes had the lowest average rates. As another example, research from Energy Innovation shows that the U.S. can achieve 100 percent zero-carbon power by 2035 without increasing customer costs.[22]

The same is either already true, or soon to be true, for zero-emission vehicles as well. Myriad studies show cost parity for light-duty and heavy-duty ZEVs being achieved by mid-decade or shortly thereafter. A carbon neutrality study conducted by the University of California (UC) Institute of Transportation Studies and funded by the California Environmental Protection Agency (CalEPA) shows that achieving carbon neutrality in the transportation sector will save Californians $167 billion through 2045.[23] Similar research from the Goldman School of Public Policy at UC Berkeley finds that achieving 100 percent light-duty ZEV sales nationwide would save consumers $2.7 trillion through 2050; equivalent to $1,000 per household, per year, for 30 years.[24]

22 *Phadke, A. et al. 2020. "Illustrative Pathways to 100 Percent Zero Carbon Power by 2035 Without Increasing Customer Costs, Energy Innovation." September.*

23 *Brown, A. L., et al. 2021. Driving California's Transportation Emissions.*

24 *Goldman School of Public Policy. 2021. 2035: The Report: Transportation. UC Berkeley. April.*


Many of these outcomes are a direct result of California's vision and policy development to advance clean energy and climate solutions, including through the Renewables Portfolio Standard, Advanced Clean Cars II regulations, SLCP Reduction Strategy, and others. While the world collectively has not yet fully deployed clean energy and climate solutions at the scale needed to adequately address climate change, California has made tremendous progress—even since the last Scoping Plan update in 2017. Continued ambition, leadership, and climate policy development from California will help the state achieve the scale of emissions reductions needed from technologies and strategies that are already cost-effective or close to it today, and will move additional technologies and strategies to that point in the near future. Achieving those outcomes and reducing costs for the entire array of climate solutions needed to achieve carbon neutrality and then maintain net-negative emissions will prove the true measure of California's success. This will enable California to not just meet our own climate targets, but to ultimately develop the replicable solutions that can scale globally to address global warming.

## Continue with a Portfolio Approach

Over the past decade and a half, the state has undertaken a successful three-pronged approach to reducing GHGs: incentives, regulations, and carbon pricing. The 2017 Scoping Plan leveraged existing programs such as the Renewables Portfolio Standard, Advanced Clean Cars, Low Carbon Fuel Standard, Short-lived Climate Pollutant Strategy, mobile source measures to achieve federal air quality targets, and a Cap-and-Trade Program, among others, to lay out a technologically feasible and cost-effective path to achieve the 2030 GHG reduction target. When looking toward the 2045 climate goals and the deeper GHG reductions needed across the AB 32 GHG Inventory sectors, all of the existing programs must be evaluated and, as necessary, strengthened to support the rapid production and deployment of clean technology and energy, as well as the increased pace and scale of actions on our natural and working lands.

The challenge before us requires us to keep all tools on the table. Given the climate mitigation co-benefits, critical actions to deliver near-term air quality benefits, such as those included in the State Implementation Plan to achieve the federal air quality standards, are incorporated into this Scoping Plan, as are new legislative mandates to decarbonize the electricity and cement sectors. And, if additional gaps are identified, new programs and policies must be developed and implemented to ensure all sectors are on track to reduce emissions. Opportunities to leverage these programs to address ongoing air quality disparities must also be considered, along with targeted environmental justice policies such as the AB 617 Community Air Protection Program and the investments made possible through the California Climate Investments Program.

## Conclusion

California has never undertaken such a comprehensive, far-reaching, and transformative approach to fighting climate change as that called for in this plan. Once implemented, it will place every aspect of how we live, work, play, and travel in California on a more sustainable footing, with a focus on directly benefitting those communities already most burdened by pollution. This comprehensive approach reflects how climate change is already changing life in California. We have all experienced the impacts of devastating wildfires, extreme heat, and drought. Despite much progress, California still has some of the worst air pollution in the nation, especially in the San Joaquin Valley and the Los Angeles Basin, which is driven by the continued use of fossil fuel-powered trucks and cars.

This Scoping Plan provides a solution; a way forward and a vision of a California where we can and will address those impacts. This plan is fundamentally based on hope. It is a hope grounded in experience and science that we can fundamentally improve the California we leave to future generations. The plan is built on the legacy of effective actions and on the conviction that we can effectively marshal the combined capabilities of California—from state, regional, tribal, and local governments to industry to our research institutions, and most importantly, to the nearly 40 million Californians who will benefit from the actions laid out in the plan. It addresses the challenge of our generation by laying out a pathway and guideposts for action across three decades. But the Scoping Plan is only that: a plan. The hard work—and hopeful work—is putting its recommendations into action. And there is no time to waste.

## Post-adoption of the Scoping Plan

As with previous Scoping Plans, CARB Board approval is the beginning of the next phase of climate action. Specifically, approval of this plan catalyzes a number of efforts, including the development of new regulations as well as amendments to strengthen regulations and programs already in place, not just at CARB but across state agencies. The unprecedented rate of transition will also require the identification and removal of market and implementation barriers to the production and deployment of clean technology and energy. All of these actions and more will be needed if we are to achieve our climate goals.

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# Chapter 1: Introduction

"The debate is over around climate change. Just come to the state of California. Observe it with your own eyes."

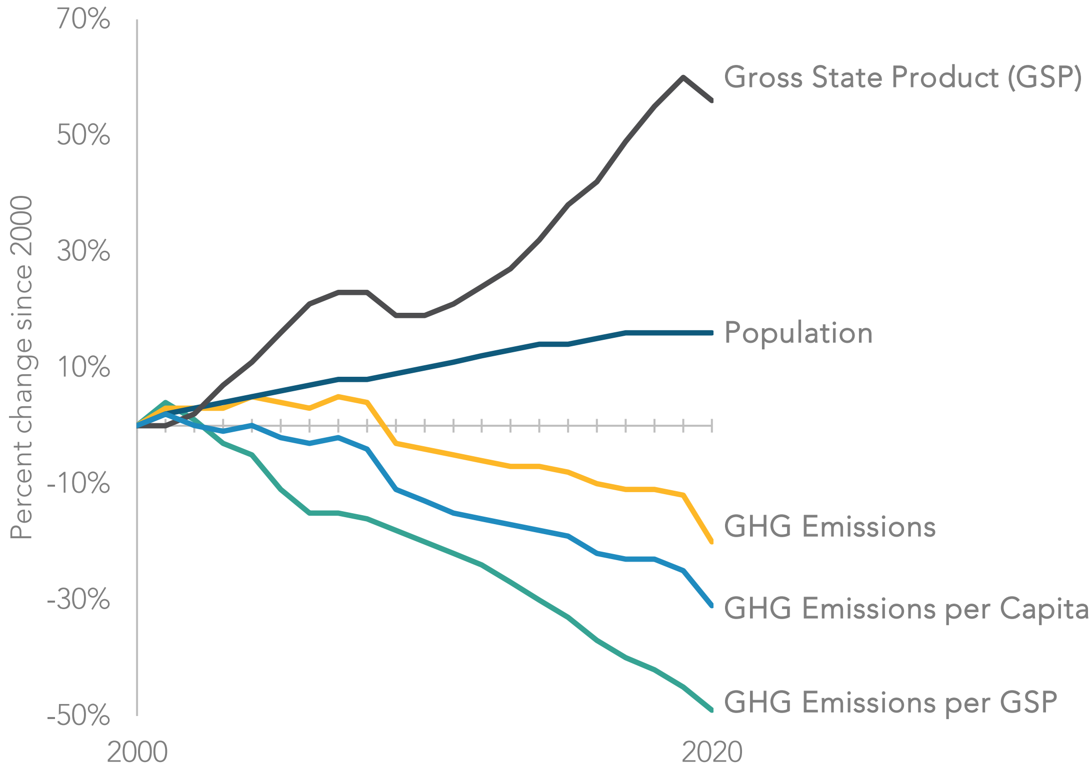
- California Governor Gavin Newsom in September 2020 after surveying the devastation caused by catastrophic wildfires

The impacts of climate change are no longer a distant threat on the horizon—they are right here, right now, with a growing intensity that is adversely affecting our communities and our environment, here in California and across the globe. The science that, decades ago, predicted the impacts we are currently experiencing is even stronger today and unambiguously tells us what we must do to limit irreversible damage: we must act with renewed commitment and focus to do more and do it sooner. That science is indisputable. Unless we increase ambition, we will be faced with more fire, more drought, more temperature extremes, and deadly, choking air pollution. The future of our state—our communities, economy, and ecosystems—is inextricably tied to the way we respond in this decade and the partnerships we forge along the way.

The impacts of climate change fall most heavily on frontline communities that bear the brunt of extreme heat, drought, wildfires, and other effects. Low-income communities and communities of color are also disproportionately impacted by fossil fuel combustion-related air pollution and related health problems. The continued phaseout of fossil fuel combustion will advance both climate and air quality goals and will deliver the greatest health benefits to the most impacted communities.

As it has responded to this climate crisis, California has established itself as a global leader in science-based, public health-focused climate change mitigation and air quality control. The California Legislature has worked with both Republican and Democratic governors to advance action on public health and environmental protections—and California has made progress on addressing climate change during periods of both Republican and Democratic federal administrations. Since the passage of Assembly Bill 32 (AB 32) (Núñez and Pavley, Chapter 488, Statutes of 2006), California has developed bold, creative, and durable policy solutions to protect our environment and public health, all while growing our economy. In fact, California met the target established in AB 32—a return of greenhouse gas (GHG) emissions to 1990 levels by 2020—years ahead of schedule, even as the state established itself as the one of the largest economies in the world. As Figure 1-1 below shows, California's emissions and economic growth have continued to decouple, and California is now the fifth largest economy in the world.

**Figure 1-1: California total and per capita GHG emissions**[25]




Recognizing both California's early successes in achieving GHG emissions reductions while growing the economy, as well as the worsening impacts of climate change, our governors and legislators have continued to enact ambitious goals. California's unwavering commitment to address climate change is based on indisputable science and data. This commitment is also informed by our collective efforts to address environmental justice and advance racial equity, such that race will no longer be a predictor for disproportionate environmental burdens faced by low-income communities and communities of color. As the Office of Environmental Health Hazard Assessment's

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[25] Due to the global pandemic, 2020 is an outlier year and should not be considered indicative of a trend; emissions are likely to increase as economies recover from the impacts of the pandemic.

(OEHHA's) recent analysis of race/ethnicity and air pollution vulnerability and CalEnviroScreen 4.0 scores demonstrate, much work remains to be done.[26]

Many of California's environmental policies have served as models for similar policies in other U.S. states, and at national and international levels. Moving forward, California will continue its pursuit of collaborations and advocacy for action to address climate change at all levels of government. While California is responsible for just one percent of global GHG emissions, and we must do our part, we also play an important role in exporting both political will and technical solutions to address the climate crisis globally.

Today, we have a chance to re-envision California's future and set the state on a path to be carbon neutral no later than 2045 while advancing equity, addressing environmental justice, and continuing to grow our economy. This Scoping Plan provides a roadmap outlining key policies we can implement to achieve our climate goals while improving the health and welfare of Californians and addressing disparities in health outcomes to create a more equitable future. It will enable us to turn the corner in our efforts to protect and preserve our critical natural and public resources, all while providing unparalleled opportunities for clean, pollution-free economic growth.

## Severity of Climate Change Impacts

With the increasing severity and frequency of drought, wildfire, extreme heat, and other impacts, Californians just have to look out their windows to know that climate change is real and rapidly getting worse. The impacts we thought we would see in the decades to come are happening now. We must act decisively to both reduce our GHG emissions and build resilience to these impacts for ourselves, future generations, and our iconic landscapes.

### Wildfires

Of the twenty largest wildfires ever recorded in California, nine occurred in 2020 and 2021. The worst wildfire season in California's recorded history was in 2018, with over 24,226 structures damaged or destroyed and over 100 lives lost. The largest wildfire season ever recorded in state history was in 2020, where more than 4.3 million acres burned, albeit at different intensity and with varying ecological impacts, and over 112 million metric tons of

[26] OEHHA and CalEPA. 2021. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

carbon dioxide ($CO_2$) emitted into the atmosphere.[27] The economic damage of these fires was estimated to be over $10 billion in property damage and over $2 billion in fire suppression costs.[28] The Camp Fire, which destroyed much of Paradise, California, was the world's costliest natural disaster in 2018, with overall damages of $16.5 billion.[29] It was also the deadliest fire in California history, with 85 civilian fatalities. Wildfires have always been part of California's natural ecology and will continue to be. However, changes to the state's climate and precipitation expands the footprint of wildfire threat, severity, and intensity, with one quarter of California—more than 25 million acres—now classified as being under very high or extreme fire threat.[30]

The impacts of wildfire smoke have been linked to respiratory infections, cardiac arrests, low birth weight, mental health conditions, and exacerbated asthma and chronic obstructive pulmonary disease.[31] In 2020, with all of California covered by wildfire smoke for over 45 days—and 36 counties for at least 90 days—maximum fine particulate ($PM_{2.5}$) levels persisted in the "hazardous" range of the Air Quality Index for weeks in several areas of the state.[32,33]

Catastrophic wildfire damages extend beyond human health and the economy. The Castle Fire in 2020 and the KNP Complex and Windy Fires in 2021 led to the loss of an unprecedented number of giant sequoias: an estimated 13 to 19 percent of the giant

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27 CARB. 2020. Public Comment Draft Greenhouse Gas Emissions of Contemporary Wildfire, Prescribed Fire, and Forest Management Activities. https://ww3.arb.ca.gov/cc/inventory/pubs/ca_ghg_wildfire_forestmanagement.pdf.

28 News18. 2021. San Francisco Bay Area Receives its First Wildfire Warning of 2021, After California Concludes its Driest Year. https://www.news18.com/news/buzz/san-francisco-bay-area-receives-its-first-wildfire-warning-of-2021-after-california-concludes-its-driest-year-3722897.html.

29 Munich RE. 2019. Extreme Storms, Wildfires and Droughts Cause Heavy Nat Cat Losses In 2018. https://www.munichre.com/en/company/media-relations/media-information-and-corporate-news/media-information/2019/2019-01-08-extreme-storms-wildfires-and-droughts-cause-heavy-nat-cat-losses-in-2018.html#-1808457171.

30 CARB. No date. Wildfires. https://ww2.arb.ca.gov/our-work/programs/wildfires/about.

31 Reid, C. E., M. Brauer, F. H. Johnston, M. Jerrett, J. R. Balmes, and C. T. Elliott. 2016. "Critical Review of Health Impacts of Wildfire Smoke Exposure." *Environmental Health Perspectives* http://dx.doi.org/10.1289/ehp.1409277.

32 Vargo J. A. 2020 (updated in 2021 using the NOAA Hazard Mapping System). "Time Series of Potential US Wildland Fire Smoke Exposures." *Frontiers in Public Health* https://doi.org/10.3389/fpubh.2020.00126.

33 CalFire. 2020 *Fire Siege Report.* https://www.fire.ca.gov/media/hsviuuv3/cal-fire-2020-fire-siege.pdf.

sequoia population in the Sierra Nevada. An iconic species, giant sequoias are the largest trees on earth, with exceptional longevity outside of climate extremes.[34,35]

It is clear that we must take drastic measures to prepare for future wildfires, which is why California invested $2.7 billion in wildfire resilience from fiscal years 2020 to 2023. The exponential increase in funding launched more than 552 wildfire resilience projects in less than a year, and CAL FIRE met its 2025 goal of treating 100,000 acres a full three years ahead of schedule. Since Fiscal Year 2019–20, treatment work has significantly increased, and CAL FIRE has averaged 100,000 acres treated each fiscal year.

Although we are making progress, we have a lot more work to do in order to achieve our goal of treating one million acres annually by 2025. The Governor's Wildfire and Forest Resilience Strategy details 99 actions needed to address the key drivers of catastrophic wildfires, ramp up the pace and scale of forest management, and make threatened communities more resilient to catastrophic fires. It is also important to note that natural wildfire cycles are a part of a sustainable forest ecosystem and will continue to play a role in a healthy forests' future. We should not expect wildfires to cease, but we must manage our lands to address catastrophic wildfires that result from buildup of carbon stocks due to our interventions to suppress wildfires and from climate change resulting from fossil fuel combustion.

## Drought

Drought is a recurring feature of the California climate that has been intensified by increasingly warmer average temperatures. Anthropogenic climate trends have exacerbated drought conditions; human-caused climate change accounts for 19 percent of drought severity and 42 percent of the soil moisture deficit in this region since 2000. The governor declared a drought state of emergency in October 2021, and as of September 2022, 94 percent of California was in severe drought, and 99.8 percent[36] of the state was in at least moderate drought. The first three months of 2022 were the driest January, February, and March on record in California.[37] The harsh drought conditions affecting California are part of a larger megadrought—a drought lasting more than two

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[34] Shive, K., C. Brigham, T. Caprio, and P. Hardwick. 2021. 2021 Fire Season Impacts to Giant Sequoias. The Nature Conservancy and National Park Service. https://www.nps.gov/articles/000/2021-fire-season-impacts-to-giant-sequoias.htm.

[35] Shive, K. L., A. Wuenschel, L. J. Hardlund, S. Morris, M. D. Meyer, and S. M. Hood. 2022. "Ancient Trees and Modern Wildfires: Declining Resilience to Wildfire in the Highly Fire-adapted Giant Sequoia." *Forest Ecology and Management* 511, 120110. https://doi.org/10.1016/j.foreco.2022.120110.

[36] Drought.gov. California. National Oceanic and Atmospheric Administration (NOAA) and the National Integrated Drought Information System. https://www.drought.gov/states/california.

[37] Drought.ca.gov. September 26, 2022. California Drought Update. https://drought.ca.gov/media/2022/09/Weekly-CA-Drought-Update-09262022-FINAL.pdf.

decades—that has been ongoing in the Southwestern region of North America since 2000. The past 22 years have been the region's driest period since at least 800 CE.[38]

While large urban water districts with diversified sources of water supply have maintained water deliveries to customers through the drought, hundreds of individual well owners and some small water systems have suffered disruption. The state is providing funding for water system consolidation and modernization projects in small communities, emergency repairs and replacements for dry wells, and bottled and hauled water deliveries. A 2021 law requires small suppliers to create drought contingency plans. During the drought of the last three years the state has delivered emergency drinking water assistance to nearly 10,000 households and 150 water systems.

California agriculture is responsible for more than half of all U.S. domestic fruit and vegetable production, and in 2021 drought resulted in the fallowing of nearly 400,000 acres of fields.[39] Direct crop revenue losses were approximately $962 million, and total economic impacts were more than $1.7 billion, with over 14,000 full- and part-time job losses.[40] During the 2011–2017 drought, California's agricultural industry suffered at least $5 billion in losses.[41] The 2022–23 budget includes $100 million to support agricultural water conservation practices, provide on-farm technical assistance, and provide direct relief to small farm operators.

Though native California species are adapted to drought, human engineering has altered most streams and wetlands in the state, making drought increasingly stressful to fish and wildlife. The state has conducted hundreds of fish and amphibian rescues in this drought to move creatures from diminished habitat, upgraded hatcheries, and boosted hatchery production, and has hauled millions of young hatchery salmon to San Francisco Bay to avoid adverse river conditions. State biologists monitor dozens of streams statewide and have negotiated voluntary agreements with landowners and water users to improve stream flows and temperatures.

California has started to implement major policies to build resilience to combat drought—such as the Sustainable Groundwater Management Act of 2014, the governor's Water Resilience Portfolio (2020), the governor's Water and Supply Strategy (August 2022), and

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[38] Williams, A. P., B. I. Cook, and J. E. Smerdon. 2022. "Rapid Intensification of The Emerging Southwestern North American Megadrought in 2020–2021." *Nature Climate Change* https://doi.org/10.1038/s41558-022-01290-z.

[39] Medellín-Azuara, J. 2022. *Economic Impacts of the 2021 Drought on California Agriculture.* University of California Merced. https://wsm.ucmerced.edu/wp-content/uploads/2022/02/2021-Drought-Impact-Assessment_20210224.pdf.

[40] Medellín-Azuara. *Economic Impacts of the 2021 Drought*.

[41] National Resources Defense Council (NRDC). 2019. Climate Change and Health in California. Issue Brief. https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf.

new standards for indoor, outdoor, and industrial water use. However, it is crucial that we take further actions to minimize the impacts of drought in the years to come.

## Extreme Heat

California's hottest summer on record was 2021.[42] Death Valley recorded the world's highest reliably measured temperature (130°F) in July 2021, breaking its own record (129°F) from summer 2020.[43] Meanwhile, Fresno also broke one of its own records, with 64 days over 100°F in 2021.[44] This is part of a trend: the daily maximum average temperature, an indicator of extreme temperature shifts, is expected to rise 4.4°F–5.8°F by 2050 and 5.6°F–8.8°F by 2100.[45] Heat waves that result in public health impacts are also projected to worsen throughout the state. By 2050, these heat-related health events are projected to last two weeks longer in the Central Valley and occur four to ten times more often in the Northern Sierra region.[46]

Heat ranks among the deadliest of all climate hazards in California, and heat waves in cities are projected to cause two to three times more heat-related deaths by mid-century.[47] Climate vulnerable communities[48] will experience the worst of these effects, as heat risk is associated and correlated with physical, social, political, and economic factors. Aging populations, infants and children, pregnant people, and people with chronic illness are especially sensitive to heat exposure.[49,50] Combining these characteristics and existing health inequities with additional factors such as poverty, linguistic isolation,

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[42] NOAA. 2022. Climate at a Glance. https://www.ncdc.noaa.gov/cag/statewide/time-series/4/tavg/3/8/1895-2021?base_prd=true&firstbaseyear=1901&lastbaseyear=2000.

[43] Masters, J. 2021. Death Valley, California, breaks the all-time world heat record for the second year in a row. Yale Climate Connections. https://yaleclimateconnections.org/2021/07/death-valley-california-breaks-the-all-time-world-heat-record-for-the-second-year-in-a-row/.

[44] NOAA. Climate Data Online Search. Accessed on 16 March 2022. https://www.ncdc.noaa.gov/cdo-web/search.

[45] Governor's Office of Planning and Research (OPR), CEC, and CNRA. 2018. *California's Fourth Climate Change Assessment*. Page 23. https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.

[46] OPR, CEC, and CNRA. *California's Fourth Climate Change Assessment - Statewide Summary Report.* https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.

[47] Ostro, B., S. Rauch, and S. Green. 2011. "Quantifying the health impacts of future changes in temperature in California." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/21975126/.

[48] CARB. Priority Populations. California Climate Investments. https://www.caclimateinvestments.ca.gov/priority-populations.

[49] Basu, R. 2009. "High Ambient Temperature and Mortality: A Review of Epidemiologic Studies from 2001 to 2008." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/19758453/.

[50] Basu, R., and B. Malig. 2011. "High Ambient Temperature and Mortality in California: Exploring the Roles of Age, Disease, and Mortality Displacement." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/21981982/.

housing insecurity, and the legacy of racist redlining practices, can put individuals at a disproportionately high risk of heat-related illness and death.[51,52] Rising temperatures will also speed up smog-forming chemical reactions, leading to worse asthma, reduced lung function, cardiac arrest, and cognitive decline. African American, American Indian/Alaskan Native, and Puerto Rican Californians are particularly sensitive to smog, as they are between 28.6 and 132.5 percent more likely to be diagnosed with asthma than white Californians.[53]

In addition to the dangers to public health, California's September 2022 heat wave is particularly illustrative of how more frequent extreme heat strains the state's infrastructure we depend on to adapt to a changing climate. For example, as all-time high temperature records were broken in Sacramento, San Jose, Santa Rosa and Fairfield, electricity demand for air conditioning threatened to overwhelm the state power supply.[54]

California has taken major steps to protect communities from the impacts of extreme heat. Our recent budgets invest $800 million to cool our schools and neighborhoods, including projects to reduce urban overheating. The Extreme Heat Action Plan, released in April 2022, outlines the all-of-government approach California is taking to reduce urgent risks and build long-term resilience to the impacts of extreme heat. In September 2022, Governor Newsom signed multiple bills addressing extreme heat, including AB 2238 (Rivas, Chapter 264, Statutes of 2022), which will create the nation's first extreme heat advance warning and ranking system to better prepare communities ahead of heat waves. The Administration is committed to addressing extreme heat, but we still have a lot of work to do.

Wildfires, drought, and extreme heat are some of the most pronounced climate impacts California is experiencing, but they are not the only ones. Sea level rise, rising ocean temperatures, ocean acidification, and inland flooding are also already having devastating impacts on our communities, ecosystems, and economy, and will continue to do so in the years and decades to come. The decisions and actions that we take today will determine how strongly we will feel the impacts of climate change in the future.

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[51] Hoffman, J. S., V. Shandas, and N. Pendleton. 2020. "The Effects of Historical Housing Policies on Resident Exposure to Intra-Urban Heat: A Study of 108 US Urban Areas." MDPI. https://www.mdpi.com/2225-1154/8/1/12/htm.

[52] U.S. Climate Resilience Toolkit. No date. Heat and Social Inequity in the United States. https://toolkit.climate.gov/tool/heat-and-social-inequity-united-states.

[53] NRDC. 2019. Climate Change and Health. Issue Brief. https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf.

[54] Samenow, Jason. 2022. No September on record in the West has seen a heat wave like this. *The Washington Post.* September 9. https://www.washingtonpost.com/climate-environment/2022/09/08/western-heatwave-records-california-climate/.

# Imperative To Act

## Consequences of Further Warming

The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) found that it will not be possible to keep global warming within the threshold of 1.5°C to avoid the most severe impacts of climate change unless we make immediate and large-scale reductions in GHG emissions. It finds that atmospheric concentrations of $CO_2$ have increased by 50 percent since the industrial revolution, and that they continue to increase at a rate of two parts per million each year.[55] Without immediate action, the world will exceed 1.5°C (or 2.7°F) warming by the 2030s, and no later than 2040.

While every tenth of a degree matters—every incremental increase in warming brings additional negative impacts—climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2°C (or 3.6°F) warming, compared to 1.5°C.[56] To remain below 1.5°C with limited or no overshoot of that threshold, global net anthropogenic $CO_2$ emissions need to be cut by about half by 2030 and reach net-zero by 2050.

If we fail to make rapid changes, we may not be able to limit global warming to 2°C,[57] and the consequences of inaction would be catastrophic. Our planet is already 1.2°C warmer than pre-industrial times due to human-induced warming, and many impacts we are already experiencing, such as sea level rise, are "irreversible" for centuries to millennia.[58] Californians with the fewest resources, who are disproportionately low-income communities and communities of color, are the most vulnerable to the impacts of climate change. While the human costs associated with health impacts can never be fully monetized, a recent report finds that the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years.[59]

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[55] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.
[56] IPCC. 2018. *Special Report: Global Warming of 1.5°C.* World Meteorological Organization. https://www.ipcc.ch/sr15/.
[57] IPCC. 2021. Summary for Policymakers. In: *Climate Change 2021: The Physical Science Basis.* Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. In Press. https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM_final.pdf.
[58] United Nations. 2021. IPCC report: 'Code red.' https://news.un.org/en/story/2021/08/1097362#:~:text=%27Code%20red%20for%20humanity%27&text=We%20are%20at%20imminent%20risk,%2C%20to%20keep%201.5%20alive.%22.
[59] Alwis, D. D., and V. S. Limaye. No date. *The Costs of Inaction*. https://www.nrdc.org/sites/default/files/costs-inaction-burden-health-report.pdf.

Any delays in action or insufficient action are a threat to public health and the environment. The impacts to our economy would be devastating as well. While not specific to California, a 2022 report from Deloitte Economics Institute finds that failing to take sufficient action to reduce emissions could result in economic losses to the U.S. of more than $14.5 trillion over the next 50 years.[60] On a hopeful note, however, the report finds that if the country invests now and in the coming years in a net-zero economy, $3 trillion could be added to the economy over the next 50 years. The U.S. annual gross domestic product (GDP) would be 2.5 percent higher in 2070 in this fast-action scenario than in the delayed action scenario. The lessons for California from these analyses are clear: invest now or pay the price later. As shown in Figure 1-2, inaction can lead to negative consequences for individuals, communities, the economy, and society as a whole. As discussed later, Governor Newsom and the Legislature have accepted this imperative and made significant investments in climate action. This Scoping Plan combined with the historic investments and policy direction from the governor and Legislature, will result in unprecedented action to address the climate crisis.

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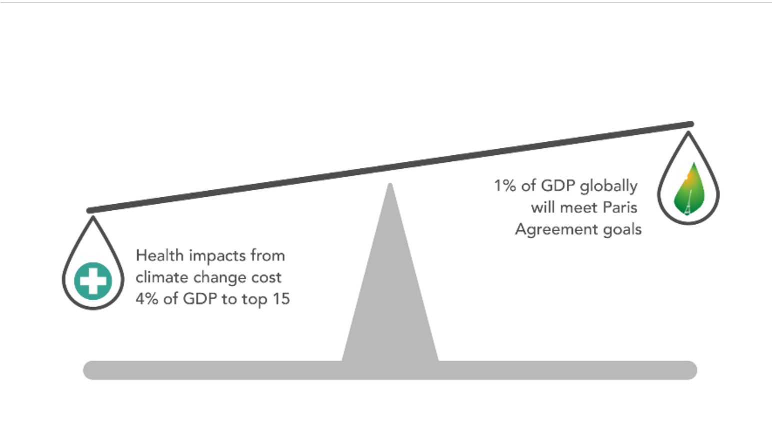
[60] Deloitte. 2022. *The Turning Point.* https://www2.deloitte.com/content/dam/Deloitte/us/Documents/about-deloitte/us-the-turning-point-a-new-economic-climate-in-the-united-states-january-2022.pdf?id=us:2el:3dp:wsjspon:awa:WSJSBJ:2021:WSJFY22.

**Figure 1-2: The real costs of inaction**[61]

**Costs of Inaction Outweigh Costs of Action for World's Largest 15 GHG Emitters**




*Exposure to air pollution causes 7 million deaths worldwide every year and costs an estimated US$5.11 trillion in welfare losses globally. In the 15 countries that emit the most greenhouse gas emissions, the health impacts of air pollution are estimated to cost more than 4% of their GDP. Fossil fuel combustion contributes to both air pollution and climate change. Actions to meet the Paris goals would cost about 1% of global GDP.*

# Scoping Plan Overview

## Previous Scoping Plans

The Scoping Plan is a strategy the California Air Resources Board (CARB) develops and updates at least one every five years, as required by AB 32. It lays out the transformations needed across our society and economy to reduce emissions and reach our climate targets. This Scoping Plan is the third update to the original plan that was adopted in 2008. The initial Scoping Plan laid out a path to achieve the AB 32 2020 limit of returning to 1990 levels of GHG emissions, a reduction of approximately 15 percent below business as usual.[62] The 2008 Scoping Plan included a mix of incentives, regulations, and carbon pricing, laying out the portfolio approach to addressing climate change and clearly making the case for using multiple tools to meet California's GHG targets. The 2013 Scoping Plan assessed progress toward achieving the 2020 limit and made the case for addressing

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[61] Katowice, P. 2018. *Health benefits far outweigh the costs of meeting climate change goals.* WHO. https://www.who.int/news/item/05-12-2018-health-benefits-far-outweigh-the-costs-of-meeting-climate-change-goals.

[62] CARB. 2008. *Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/document/adopted_scoping_plan.pdf.

short-lived climate pollutants (SLCPs).[63] The most recent update, the 2017 Scoping Plan,[64] also assessed the progress toward achieving the 2020 limit and provided a technologically feasible and cost-effective path to achieving the Senate Bill 32 (SB 32, Pavley, Chapter 249, Statutes of 2016) target of reducing GHGs by at least 40 percent below 1990 levels by 2030.

## Overview of this Scoping Plan

It is paramount that we continue to build on California's success by taking effective actions and doubling down on implementation of the strategies outlined here. As such, this Scoping Plan builds on and integrates efforts already underway to reduce the state's GHG, criteria pollutant, and toxic air contaminant emissions by identifying the clean technologies and fuels that should be phased in as the state transitions away from combustion of fossil fuels. By selecting and pursuing a sustainable and clean economic path, the state will continue to successfully execute existing programs, work to eliminate air pollution inequities, demonstrate the coupling of economic growth and environmental progress, and enhance new opportunities for engagement within the state to address and prepare for climate change.

The 2022 Scoping Plan for Achieving Carbon Neutrality (Scoping Plan) is the most comprehensive and far-reaching Scoping Plan developed to date. It identifies a technologically feasible and cost-effective path to achieve carbon neutrality by 2045 while also assessing the progress California is making toward reducing its GHG emissions by at least 40 percent below 1990 levels by 2030, as called for in SB 32 and laid out in the 2017 Scoping Plan.[65] The 2030 target is an interim but important stepping stone along the critical path to the broader goal of deep decarbonization by 2045. Modeling for this Scoping Plan shows that this decade must be one of transformation on a scale never seen before to set us up for success in 2045.

The relatively longer path assessed in this Scoping Plan incorporates, coordinates, and leverages many existing and ongoing efforts to reduce GHGs and air pollution, while identifying new clean technologies and energy. Given the focus on carbon neutrality, this Scoping Plan also includes discussion for the first time of the Natural and Working Lands (NWL) sectors as both sources of emissions and carbon sinks. Chapter 2 of this document

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[63] CARB. 2014. *First Update to the Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.
[64] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.
[65] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.

includes a description of a suite of specific actions to drastically reduce GHGs across all sectors. Chapter 3 provides the air quality and economic evaluations of the actions. Chapter 4 provides a broader description of the many actions needed across all sectors to achieve carbon neutrality. Chapter 5 provides an overview of the next steps and partnerships needed to implement this Scoping Plan. Guided by legislative direction, the actions identified in this Scoping Plan reduce overall GHG emissions in California and deliver policy signals that will continue to drive investment and certainty in a low carbon economy. This Scoping Plan builds upon the successful framework established by the Initial Scoping Plan and subsequent updates while identifying new, technologically feasible, and cost-effective strategies.

## Principles That Inform Our Approach to Addressing the Climate Challenge

California has decades of experience addressing the climate challenge. Through this experience, and based on extensive engagement with stakeholders through our regulatory and program development processes, we have developed a set of principles to inform our approach.

### Unprecedented Investments in a Sustainable Future

The scale of transformation needed over this decade to avoid the worst impacts of climate change and meet our ambitious climate goals is extraordinary. This is why Governor Newsom and the Legislature invested over $15 billion in climate action through the 2021–2022 California Comeback Plan, and why the 2022–2023 budget marks the beginning of the California Climate Commitment—the governor’s multi-year plan to invest $54 billion in climate action. The enacted budgets (Figure 1-3) and the California Climate Commitment represent investments of a historic scale and will advance precisely the type of all-of-government approaches necessary to create the whole-of-society changes described in this Scoping Plan that will enable us to avert the worst impacts of climate change.

**Figure 1-3: Comprehensive California climate change investments**


The *California Climate Commitment* includes the following game-changing elements:

- $10 billion for zero-emission vehicles (ZEVs), including $1.5 billion for electric school buses to protect students' health and $3 billion to build an accessible charging network. ZEV investments will particularly focus on programs such as heavy-duty vehicle and port electrification that will reduce emissions and protect public health in low-income communities.
- $2.1 billion for clean energy investments, such as long duration storage, offshore wind, green hydrogen,[66] and industrial decarbonization.
- $13.8 billion for programs that reduce emissions from the transportation sector, such as improving public transportation while also funding walking, biking, and adaptation projects.
- Over $720 million for California's higher education institutions and research that will support the next generation of climate innovations.

[66] For the purposes of this Scoping Plan, "renewable hydrogen" and "green hydrogen" are interchangeable and are not limited to only electrolytic hydrogen produced from renewables.

- Nearly $1 billion to build sustainable, affordable housing and over $1 billion to help low-income Californians realize energy cost savings through building decarbonization.
- Nearly $9 billion for wildfire risk reduction, drought mitigation, extreme heat resilience, and nature-based solutions.

These investments are incredibly important in the context of this Scoping Plan in that they accompany and help support implementation of the many policies and regulations that will continue to be necessary to achieve our 2030 and carbon neutrality targets. In addition, these incentive programs jump-start emission reduction strategies for priority sectors, sources, and technologies, leveraging private-sector investment and building sustainable, growing markets for clean and efficient technologies. Many of California's incentive programs work in concert with federal and other state programs to drive emission reductions. As an example, as California pushes to move to 100% sales of new zero emission-vehicles, including plug-in hybrid vehicles, the Newsom Administration continues to invest heavily in incentive programs that allow families, communities, and businesses to choose zero-emission vehicles. This is done while simultaneously working with the federal government, other states, and jurisdictions around the world to align policies, regulations, and incentives, creating market certainty for the automakers that serve our markets.

## Centering Equity

Prioritizing equity is just as important as the magnitude of the climate investments California is making. Addressing climate change and advancing our equity and economic opportunity goals cannot be decoupled. In line with the governor's Executive Order[67] to take additional actions to embed equity analysis and considerations, this plan works to center equity by addressing disparities for historically underserved and marginalized communities. California strives to ensure that our climate and air research, regulations, investments, and plans include provisions that specifically address and advance equity. This includes reducing and eliminating air pollution disparities, removing barriers that can prevent frontline communities from accessing benefits, lowering costs for low-income Californians, and promoting high-quality jobs. CARB's incentive programs regularly surpass their mandated equity targets, and CARB has incorporated equity-focused provisions in our research, planning, and regulatory efforts. For instance, statute requires that a minimum of 35 percent of California Climate Investments benefit low-income households along with disadvantaged and low-income communities (referred to as *priority*

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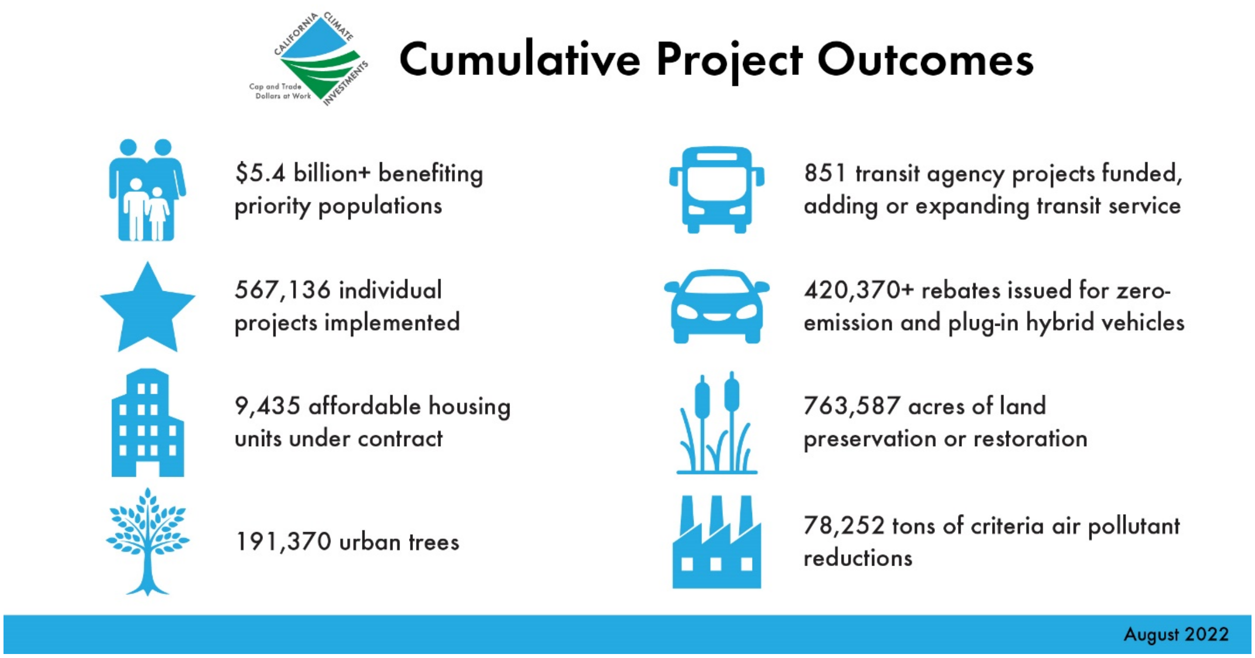
[67] Executive Department. State of California. 2022. Executive Order N-16-22. GSS_9320_2-20220912152941 (ca.gov).

*populations*). However, 48 percent—over $5.4 billion—of implemented California Climate Investments project funding is benefiting priority populations, greatly exceeding the statutory minimums (see Figure 1-4). Senate Bill 535 (De León, Chapter 830, Statutes of 2012) and AB 1550 (Gomez, Chapter 369, Statutes of 2016) direct state and local agencies to make significant investments using auction proceeds to assist California's most vulnerable communities. Under these laws, a minimum of 25 percent of the total investments are required to be located within and provide benefits to disadvantaged communities, and at least 10 percent of the total investments must benefit low-income communities and households. Moving forward, the state will continue to devote a greater share of incentive funding to priority populations, with the light-duty vehicle incentive program as just one example. We can simultaneously confront the climate crisis and build a more resilient, just, and equitable future for all communities.

**Figure 1-4: California climate investments cumulative outcomes**[68,69]




## Role of the Environmental Justice Advisory Committee

To inform the development of the Scoping Plan, AB 32 calls for the convening of an Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB in developing the Scoping Plan, and any other pertinent matter in implementing AB 32. It requires that the Committee be comprised of representatives from communities with the most significant exposure to air pollution, including communities with minority populations and/or low-income populations. On January 25, 2007, CARB appointed the first

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[68] CARB. 2022. California Climate Investments program implements $10.5 billion in greenhouse gas-reducing programs, expected to reduce 76 million metric tons of emissions. April 11. https://ww2.arb.ca.gov/news/california-climate-investments-program-implements-105-billion-greenhouse-gas-reducing-projects.

[69] SB 535 and AB 1550 require investments located in and benefiting low-income communities and households, which are termed *priority populations. Disadvantaged communities* are currently defined by CalEPA as the top 25 percent of communities experiencing disproportionate amounts of pollution, environmental degradation, and socioeconomic and public health conditions according to the Office of Environmental Health Hazard Assessment's *CalEnviroScreen tool,* plus certain additional communities including federally recognized Tribal Lands. Low-income communities and households are defined by statute as those with incomes either at or below 80 percent of the statewide median or below a threshold designated as low-income by the Department of Housing and Community Development.

Environmental Justice Advisory Committee to advise it on the Initial Scoping Plan and other climate change programs.

For this Scoping Plan, CARB reconvened the EJ Advisory Committee in May 2021. The committee is currently comprised of 14 environmental justice and disadvantaged community representatives, including the EJ Advisory Committee's first tribal representative, who was appointed in February 2022. In October 2021, the EJ Advisory Committee formally created eight workgroups. These workgroups are a space for EJ Advisory Committee members to better understand specific sectors of the Scoping Plan and to assist the EJ Advisory Committee in the development of recommendations on this Scoping Plan. In December 2021, the EJ Advisory Committee provided scenario input responses to help shape the modeling for this Scoping Plan. In February 2022, San Joaquin Valley EJ Advisory Committee members hosted their first community workshop, with over 100 attendees. In March 2022, the CARB Board held a joint public meeting with the EJ Advisory Committee to discuss their draft preliminary recommendations for this Scoping Plan. In June 2022, over 165 attendees participated in a statewide community workshop held by EJ Advisory Committee members. The full schedule of EJ Advisory Committee Meetings and meeting materials are available on CARB's website.[70] This Scoping Plan includes references where EJ Advisory Committee Final Recommendations[71] are included in the document. The final recommendations were discussed at a joint CARB and EJ Advisory Committee Hearing on September 1, 2022.

The integration of environmental justice is critical to ensure that certain communities are not left behind. The AB 32 EJ Advisory Committee provided recommendations on September 30 in advance of the final Scoping Plan. There are footnotes to indicate where there is alignment between the AB 32 EJ Advisory Committee's recommendations and this Scoping Plan. While the language in the text may not fully incorporate the specific EJ Advisory Committee's recommendation, the footnotes do acknowledge the places in the text where there is general alignment with the spirit of the EJ Advisory Committee's recommendation.

## Partnering with Tribes

[70] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.
[71] Environmental Justice Advisory Committee. September 30, 2022. 2022 Scoping Plan Recommendations. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf.

There are 109 federally recognized tribes and over 60 non-federally recognized tribes in California. [72] In 2011, Governor Brown issued Executive Order B-10-11, recognizing and reaffirming the inherent right of tribes to exercise sovereign authority over their members and territory and directing state agencies to engage in government-to-government consultation with tribe and to work to develop partnerships and consensus.[73] In 2019, Governor Newsom issued Executive Order N-15-19, which acknowledges and apologizes on behalf of the state for the historical "violence, exploitation, dispossession and the attempted destruction of tribal communities."[74] Establishing partnerships with tribal leaders to incorporate their priorities, traditional expertise, and knowledge will be important to achieving California's climate goals. The Scoping Plan includes actions that tribal partners can voluntarily implement for sources under their jurisdiction (e.g., transitioning to zero emission fleets, installing infrastructure and control technologies, conducting climate smart land management). The Scoping Plan also uplifts the importance of having our tribal partners help guide actions that may impact tribal cultural resources and of benefitting from tribal input.

We also need alignment between state and local partners and tribes on actions related to land-use decisions. This means respecting and reinforcing tribal sovereignty and self-determination. As tribes do not always draw clear lines between the "natural" and "cultural" resources of a place, taking a holistic perspective will result in positive impacts in ability to address the complex issues of land management and regulatory undertakings.

Tribes have an intimate and historical knowledge of places and should be engaged early on to inform planning and future management related to activities that may impact tribal resources and areas including potential funding opportunities, technical assistance, and capacity building, where appropriate. Additionally, tribes should be involved in the identification of their own significant resources and areas of use. As decisions are made related to Scoping Plan undertakings, agencies should recognize and appropriately consider cultural resources and management from the beginning, not as an afterthought; and consider how the project could impact tribes.

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[72] These numbers are subject to change depending on determinations made by the Bureau of Indian Affairs (BIA) and the Native American Heritage Commission (NAHC). Please consult the most current Federal Register for a list of federally recognized tribes and the NAHC for a list of non-federally recognized tribes in California. As of the date of the Scoping Plan, the current list for federally recognized tribes is located at 87 Fed. Reg. 4636 (Jan. 28, 2022).

[73] Executive Order B-10-11. https://www.ca.gov/archive/gov39/2011/09/19/news17223/index.html#:~:text=EXECUTIVE%20ORDER%20B-10-11%20Published%3A%20Sep%2019%2C%202011%20WHEREAS,and%20affirmed%20in%20state%20and%20federal%20law%3B%20and.

[74] Executive Order N-15-19. https://tribalaffairs.ca.gov/wp-content/uploads/sites/10/2020/02/Executive-Order-N-15-19.pdf.

Finally, to the extent allowed by law, traditional ecological knowledge and culturally sensitive information should be protected, as this is information that may not be common knowledge and may not be known outside the tribe, as each tribe is unique and influenced by its local environment and cultural practices. Protection of this information will help foster productive relationships with tribes and should be included as part of the process. CARB and other agencies should continue to foster relationships with tribal partners.

## Maximizing Air Quality and Health Benefits

The state has over 50 years of experience successfully cleaning the air in California by addressing criteria pollutants and toxic air contaminants from mobile and stationary sources. CARB has been a leader in measuring, evaluating, and reducing sources of air pollution that impact public health. Its air pollution programs have been adapted for national programs and emulated in other countries. Significant progress has been made in reducing diesel particulate matter (PM), which is a designated toxic air contaminant, and many other hazardous air pollutants. CARB partners with local air districts to address stationary source emissions and adopts and implements state-level regulations to address sources of criteria and toxic air pollution, including mobile sources. CARB also collaborates with federal agencies to address air pollution from sources primarily under federal jurisdiction. In many instances, actions to reduce fossil fuel combustion and achieve federal air quality standards also help to reduce GHG emissions.

However, air pollution disparities still exist, and more must be done to ensure the most vulnerable populations have safe air to breathe. California must continue to evaluate opportunities to harmonize our climate and air quality programs through innovative policymaking and by building on existing programs like the Low Carbon Fuel Standard (LCFS) and Community Air Protection Program. The LCFS includes a provision that allows electric utilities to opt-in and generate residential electric vehicle (EV) charging credits, where some of the revenues are invested back into rebate programs that address air quality and climate pollution.[75] The Community Air Protection Program[76] is the first of its kind in the country and brings together diverse stakeholders, including CARB, local air districts, and residents of environmental justice communities to increase local air monitoring and develop community-led plans to improve air quality in the communities most impacted by air pollution.

This Scoping Plan identifies actions that will deliver near-term air quality benefits to communities with the highest exposures and provide long-term GHG benefits. Many of the actions in this Scoping Plan are key elements of the 2022 State Strategy for the State

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[75] CARB. LCFS Utility Rebate Programs. https://ww2.arb.ca.gov/resources/documents/lcfs-utility-rebate-programs.

[76] CARB. Community Air Protection Program. https://ww2.arb.ca.gov/capp.

Implementation Plan to meet federal air quality standards,[77] which has a primary focus of reducing harmful air pollution and achieving federal air quality targets. California's approach of leveraging air quality and GHG policies together has yielded results. A 2022 report by the Office of Environmental Health and Hazard Assessment (OEHHA)[78] that evaluated GHG and harmful air pollution emissions from the heavy-duty vehicle (HDV) and large stationary source sectors found declines in emissions in both sectors, with the greatest declines in disadvantaged communities. Both sectors are subject to state GHG and air quality policies, in addition to federal and local rules on harmful air pollution. Because of historically racist and discriminatory practices such as redlining, both types of sources are disproportionately located adjacent to vulnerable communities, which are predominantly communities of color.[79] The key findings from the OEHHA report are as follows:

- Both HDVs and facilities subject to the Cap-and-Trade Program have reduced emissions of co-pollutants, with HDVs showing a clearer downward trend when compared to stationary sources. These emission reductions have major health benefits, including a reduction in premature pollution-related deaths.
- The greatest beneficiaries of reduced emissions from both HDVs and facilities subject to the Cap-and-Trade Program have been in communities of color and in disadvantaged communities in California, as identified by CalEnviroScreen (CES). This has reduced the emission gap between disadvantaged and non-disadvantaged communities, but a wide gap still remains.
- The transition to zero-emission HDVs will expedite further emissions reductions.
- While the progress observed is encouraging, inequities persist, and federal, state, and local climate and air quality programs must do more to reduce emissions of GHGs and co-pollutants to reduce the burden of emissions on disadvantaged communities and communities of color.

It will take all tools at all levels of government, with robust enforcement, to ensure that vulnerable communities continue to see improvements in air quality until no disparities exist in air pollution across the state.

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[77] CARB. 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/resources/documents/2022-state-strategy-state-implementation-plan-2022-state-sip-strategy.

[78] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits within Disadvantaged Communities: Progress Toward Reducing Inequities.* https://oehha.ca.gov/environmental-justice/report/ab32-benefits.

[79] CalEPA. 2021. Pollution and Prejudice. https://storymaps.arcgis.com/stories/f167b251809c43778a2f9f040f43d2f5.

## Economic Resilience

The state's efforts to tackle the climate crisis will create economic and workforce development opportunities in the clean energy economy in communities across the state. Transitioning existing skills and expanding workforce training opportunities in climate-related fields are critical for reducing harmful emissions and supporting workers in transitioning to new, high-quality jobs. The Administration's recent budgets acknowledge the challenges facing workers in industries most affected by the state's response to climate change—especially those in the fossil fuel industry. It will invest $1 billion in regional partnerships and economic diversification to create new jobs and support a local tax base and workforce transition and development once opportunities are identified. It also will invest in safety nets to protect, and support impacted communities as part of the transition to a carbon neutral economy. Specifically, the Community Economic Resilience Fund Program[80] (CERF) supports communities and regional groups in producing regional roadmaps for economic recovery and transition that prioritize the creation of accessible, high-quality jobs in sustainable industries. The budget investments create the opportunity to future-proof and increase economic resilience in the face of more frequent climate impacts and shifting economic conditions. For these investments and implementation of the Scoping Plan to be successful in supporting the transition to a carbon neutral economy, workers and affected communities must be included in ongoing dialogue to ensure a high-road transition for regional economies.

That state also recognizes it can play a more direct role in supporting a sustainable work force through its incentive programs. In 2021, Assembly Bill 680 (AB 680) (Burke, Chapter 746, Statutes of 2021) was signed into law, requiring CARB to work with the California Labor and Workforce Development Agency to update the Funding Guidelines to include new workforce standards. CARB's Funding Guidelines currently include requirements for administering agencies to, wherever possible, foster job creation within California, provide employment opportunities or job training tied to employment, and target these opportunities to priority populations. The Funding Guidelines also recommend administering agencies prioritize investments in projects that directly support jobs or a job training and placement program, and that they report the estimated employment benefits and employment outcomes for projects that meet specified criteria. These new requirements apply to agencies administering certain California Climate Investments

[80] Office of Planning and Research. Community Economic Resilience Fund. https://opr.ca.gov/economic-development/cerf/.

programs that receive continuous appropriations from the Greenhouse Gas Reduction Fund and fall into the following six categories of standards:

- fair and responsible employer standards,
- inclusive procurement policies,
- prevailing wage for construction work,
- community workforce agreements for construction projects over one million dollars,
- preference for projects with educational institutions or training programs, and
- creation of high-quality jobs. CARB will be updating the Funding Guidelines through a public process over the next year to operationalize these new requirements.

## Partnering Across Government

The Scoping Plan is an actionable plan to identify and align programs and policies to achieve California's climate targets. To realize the outcomes and deliver results in any Scoping Plan, action is critical. For this Scoping Plan, there are also actions that rely on our federal partners to take on sources primarily under their jurisdiction (such as aviation, and federally owned/managed lands) while they also continue to develop national programs for GHG reductions. The federal government is already taking major steps to advance these types of programs. The Inflation Reduction Act of 2022[81] includes $369 billion for domestic energy production and manufacturing and is expected to lead to U.S. GHG emission reductions of roughly 40 percent by 2030. Direct incentives will include those for clean vehicles and ENERGY STAR appliances, as well as improving transportation and clean energy in underserved communities.

We also need our local partners to align on actions related to land-use decisions that support sustainable, resilient, low-carbon communities and permitting for clean energy production facilities and infrastructure; diversion of organics from landfills; and other climate-related projects. State agencies also should use the Scoping Plan to review and update their own programs and policies to support the actions identified in this Scoping Plan. Importantly, the Scoping Plan also can serve as a resource as the Legislature considers new legislative direction and funding to support the state's path to carbon neutrality and continue action to address near-term air pollution disparities.

## Partnering with the Private Sector

Government cannot achieve our climate targets alone. The scale of investment needed requires both private-sector investment and partnerships with philanthropies. Public

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[81] Pub.L. No. 117-169 (August 16, 2022).

sector dollars, accompanied by strong and steady policy signals, must be a catalyst for deeper and broader investments by the private sector in both reducing emissions and building the resilience of our communities. Governor Newsom is committed to working collaboratively with businesses, including small businesses, to deploy the technologies, capital, and ingenuity that are hallmarks of the private sector.

California structures our climate policies and regulations to create market signals and certainty that spur private sector investment. For example, the Governor's Executive Order on Zero-Emission Vehicles[82] set 2035 as the target year for 100 percent zero-emission vehicle sales, creating a time horizon that allows automakers to scale up zero-emission fleets and sending a clear signal to the companies and utilities that would deploy charging infrastructure. The Executive Order has been followed by development and adoption of the Advanced Clean Cars II regulation. CARB convened auto manufacturers, environmental justice groups, labor organizations, and many other stakeholders to provide input into development of the regulation in a robust and transparent manner; again, with the aim of providing certainty for producers and consumers.

California also pursues public-private partnerships (PPP) as a mechanism to advance our collective climate goals. We know these vehicles can be effective at increasing the impact of public sector dollars and helpful in moving markets in a direction aligned with state policy. A new PPP the Administration is advancing is the Climate Catalyst Revolving Loan Fund, housed at the state's Infrastructure and Economic Development Bank (IBank). The fund offers a range of financial instruments—including flexible credit and credit support—to help bridge financing gaps currently preventing advanced climate solutions from scaling in the marketplace. The Catalyst Fund's initial areas of investment include forest biomass management and utilization (unlocking innovation to reduce wildfire threats), climate-smart agriculture, and clean energy transmission. The fund leverages public sector investments by mobilizing private finance for shovel-ready projects that are stuck in the deployment phase. As such, IBank is ideally positioned as the state's all-purpose "Green Bank," with increasing connection to federal financing programs such as US DOE's Loan Programs Office and the United States Environmental Protection Agency's (U.S. EPA) Greenhouse Gas Reduction Fund.

The Catalyst Fund builds from existing IBank financing programs that are themselves increasingly focused on the climate imperative. The IBank's Infrastructure State Revolving Fund provides supportive capital to climate-aligned projects promoted by local governments and certain nonprofit entities, and will be refining its criteria and market outreach strategies to increase its level of service. IBank's bonds program has supported

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[82] Executive Department. State of California. Executive Order N-79-20. *https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf*.

multiple large environmental projects, including more than $2 billion in "green bonds," and is poised to help expand access to the state's deep and liquid bond capital market. Within IBank's Small Business Finance Center, the new Climate Tech Loan Guarantee program encourages commercial banks to back climate-focused small businesses, leveraging federal capital to insure a portion of the private bank's loan. And through IBank's Expanding Venture Capital Access Fund program, the state is promoting greater diversity in the venture capital community, including climate equity and climate justice.

All of these financing programs exist to leverage private capital in support of the state's climate goals, and to partner with state policy agencies driving the transition. IBank will also continue to collaborate closely with the State Treasurer's Office in its provision of capital support to climate solutions, ensuring that funding flows to programs best positioned to deliver success. This partnership of public and private capital, responsive to and in communication with the climate policy community, will ensure that California gets the maximum possible benefit from its allocation of scarce resources.

## Supporting Innovation

Reaching our ambitious, deep decarbonization goals will require continued technological innovation. Investment in research, development, and deployment of clean technologies has never been more critical. Sending clear and sustained market and policy signals will encourage large and small companies alike to pursue innovation that can be scaled up and deployed here and beyond our borders. The full suite of AB 32 policies[83] has touched nearly every sector of California's economy and spurred technology innovation in the state, including the growth of technology developers, manufacturers, processors, and assemblers in many areas. Specifically, AB 32 policies and programs support both the supply side and the demand side to build new markets in California. On the supply side, AB 32 policies support businesses to demonstrate and refine technologies, and to help establish critical supply chains. On the demand side, AB 32 policies and programs provide outreach, education, and incentives—as well as disincentives—to motivate everyone from consumers to institutional purchasers to utility planners to adopt new, climate smart technologies. Innovations resulting directly from the state's climate policies include the following:

- In the past 10 years, a growing market for heavy-duty zero-emission vehicles (HD ZEVs) was established in California, and this market now represents the largest single share of North American supply and demand for HD ZEVs. Vehicle

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[83] CARB. Climate Change Programs. https://ww2.arb.ca.gov/our-work/topics/climate-change.

and component manufacturers are making long-term investments to develop and produce HD ZEVs within California.

- Total consumption of renewable diesel in the California LCFS market has skyrocketed from approximately 1.8 million gallons in 2011 to nearly 589 million gallons in 2020. The LCFS is a key driver of market development for renewable diesel and its coproducts. While the federal renewable fuel standard (RFS) and blenders tax credit also benefit producers, an analysis of their respective contributions to market development, and interviews with industry representatives and independent experts, point to LCFS as a more important factor in market development, at least in recent years.
- In the past five years, a market for small-scale energy storage in California was created where none previously existed. As of 2020, 185 megawatts (MW) of small-scale energy storage projects have been interconnected to the grid. The significant increase in deployment in the last five years is a result of the Self-Generation Incentive Program (SGIP), which significantly reduces the upfront costs to purchase and install small-scale energy storage devices, and of growing customer interest in disaster resiliency in the face of increasing risk from wildfire and related utility outages. These systems have already provided disaster resiliency benefits for residential and non-residential customers.

We have seen how quickly market barriers can be overcome in response to strong policy signals, as occurred in the solar panel and electric vehicle battery space. Government-stated priorities have a significant role in guiding private and public research, development, and deployment. This Scoping Plan unequivocally puts the marker down on the need for innovation to continue in non-combustion technologies, clean energy, $CO_2$ removal options, and alternatives for SLCPs. The five-year update to the Scoping Plan allows for a periodic evaluation of new tools to add to the state's toolkit.

## Engagement with Partners to Develop, Coordinate, and Export Policies

California works closely with other states, tribal governments, the federal government, and international jurisdictions to identify the most effective strategies and methods to reduce GHGs, manage GHG control programs, and facilitate the development of integrated and cost-effective regional, national, and international GHG reduction programs. For example, the state's Cap-and-Trade Program has been linked with Québec's since 2014, and CARB staff regularly engage with jurisdictions throughout the world on the design features of our Cap-and-Trade Program through memoranda of understanding (MOUs) and venues such as the International Climate Action

Partnership.[84] Low carbon fuel mandates similar to California's LCFS have been adopted by the U.S. EPA and by other jurisdictions, including Oregon, Washington, British Columbia, the European Union, and the United Kingdom. Many other jurisdictions from Japan to New Zealand, Australia, and the European Commission also continue to seek information and technical experience on our LCFS. California has and will continue to share information and encourage ambitious emissions reductions with interested jurisdictions, with a focus on China, India, Mexico, Canada, and the European Union. California's early action to reduce super-pollutants such as methane and other SLCPs was reaffirmed by the 2021 Global Methane Pledge signed by the U.S. and over 100 other countries at the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC).[85]

In addition, under the Clean Air Act, the federal government is authorized to allow California to set more stringent vehicle emissions regulations than federal standards. California's goals and regulations to transition to 100 percent sales of new zero-emission passenger vehicles by 2035 (including plug-in hybrid vehicles), to drayage trucks by 2035, and other trucks and buses where feasible by 2045 are being emulated by partner states across the U.S. and in jurisdictions around the world. CARB's Advanced Clean Cars II regulation, [86] which codifies these targets, was approved in August 2022, and already at least four other states have announced their plans to adopt this regulation. Earlier in June 2020 CARB adopted the Advanced Clean Truck regulation, which requires truck manufacturers to meet increasing sale targets of zero-emission trucks in California through 2035. Since adoption, at least five other states—20 percent of the U.S. truck market—have adopted this regulation. These kinds of coordinated policies help signal to vehicle manufacturers a widespread and growing demand for zero-emissions technology, which in turn helps scale production and lower costs for consumers.

With the Mexican Secretariat for Environment and Natural Resources (SEMARNAT), California has engaged in a technical exchange on clean vehicle policies and helped to establish Mexico's Emissions Trading System (being piloted in 2022). A 2019 MOU signed between California and Environment and Climate Change Canada enables in-depth collaboration on policies and programs to decarbonize vehicles, engines, and fuels. This partnership has led to tangible emissions reductions, from aligning vehicle emissions targets and policies to collaborating on emissions testing and research critical to enforcing

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[84] International Carbon Action Partnership (ICAP). Homepage. https://icapcarbonaction.com/en?msclkid=dac30cb7b4f511ec94ccd0f1ae323e98.

[85] Global Methane Pledge. Homepage. https://www.globalmethanepledge.org/.

[86] Cal. Code Regs., tit. 13, §§ 1900,1961.2, 1961.3, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, and 2903; and Test Procedures located here: https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii.

emissions limits for vehicle manufactures. At the national level, China has looked to California for cutting-edge requirements for car diagnostics and policies that promote zero-emissions vehicles. At a local level, Beijing has adopted California's vehicle emissions standards and several other progressive environmental regulations. California will continue and renew such efforts across China, including through a 2022 MOU signed with China's Ministry of Ecology and Environment.

Between 2021 and 2023, California also will serve as president of the Transport Decarbonisation Alliance, a global network of countries, regions, cities, and companies that come together to share experiences and technical expertise, and to increase the ambition and accelerate the deployment of targeted transportation decarbonization policies across freight, electric vehicle infrastructure, and active mobility. Throughout its presidency, California will focus its leadership on decarbonizing the cross-jurisdiction network of medium- and heavy-duty vehicles, both to ensure cleaner air in freight-adjacent communities and to stem the effects of climate change.

Over the years, California has also asserted the importance of and supported the ongoing efforts of state and local clean air and climate leadership. Through our participation in the Pacific Coast Collaborative alongside British Columbia, Washington, and Oregon,[87] the Under2 Coalition,[88] the U.S. Climate Alliance,[89] the International ZEV Alliance,[90] the Transportation Decarbonisation Alliance, and many more organizations, California has and will continue to build climate partnerships with state and local governments.

California also recognized the need to address the substantial emissions caused by the deforestation and degradation of tropical and other forests, and continues its work alongside other subnational governments as part of the Governors' Climate and Forests Task Force (GCF).[91] Founded in 2008, there are currently 39 GCF members, including states and provinces in Brazil, Colombia, Ecuador, Indonesia, Ivory Coast, Mexico, Nigeria, Peru, Spain, and the United States—all of whom are considering or operating programs to reduce emissions from deforestation, land-use, and rural development, and to benefit local and indigenous communities. CARB's California Tropical Forest Standard provides a rigorous methodology to assess jurisdiction-scale programs that reduce deforestation and to incentivize responsible action and investment.[92] The standard

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[87] Pacific Coast Collaborative. Homepage. *https://pacificcoastcollaborative.org/*.
[88] Under2 Coalition. Homepage. *https://www.theclimategroup.org/under2-coalition*.
[89] United States Climate Alliance (USCA). Homepage. *https://www.usclimatealliance.org/*.
[90] ZEV Alliance. Homepage. Accelerating the Adoption of Zero-Emission Vehicles. *https://zevalliance.org/*.
[91] Governors' Climate and Forests Task Force. University of Colorado Boulder: Colorado Law. *https://www.gcftf.org/*.
[92] CARB. California Tropical Forest Standard. *https://ww2.arb.ca.gov/our-work/programs/california-tropical-forest-standard*.

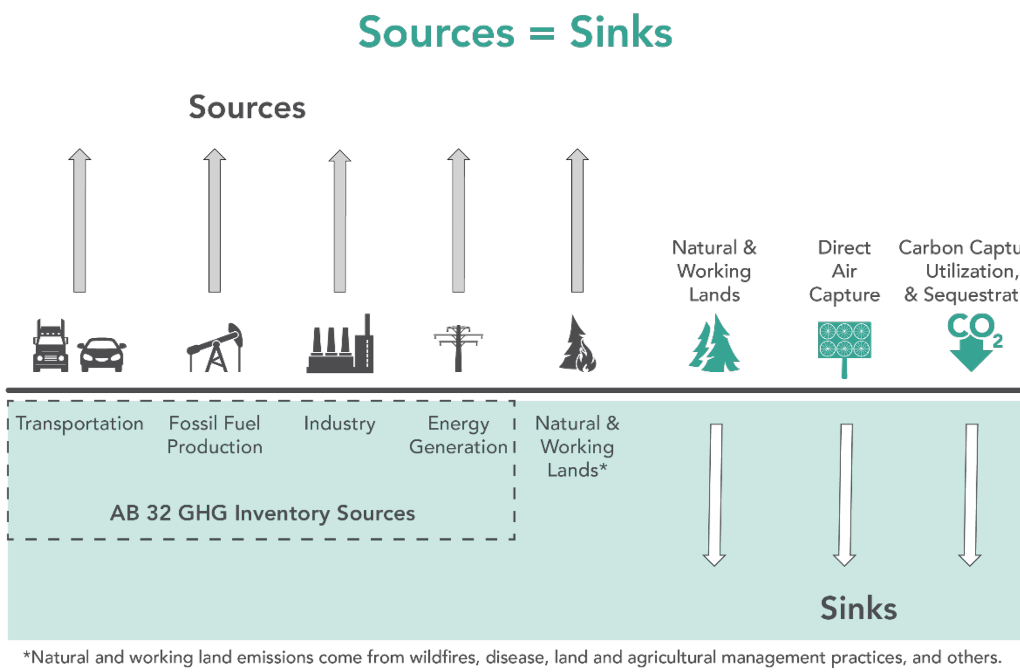
provides a strong signal to value the preservation of tropical forests over continued destructive activities such as oil exploration and extraction and ensures rigorous social and environmental safeguards for indigenous peoples and local communities.

## Working Toward Carbon Neutrality

To date, California and many other regions have focused on reducing GHG emissions from the industrial, energy, and transportation sectors. As defined in statute, the state's 2020 and 2030 targets include all in-state sources of GHG emissions—and those emissions associated with imported power that is consumed in the state. By moving to a framework of carbon neutrality, the scope for accounting is expanded to include all sources and sinks. As such, carbon neutrality is achieved when the GHG fluxes are at equilibrium—when sources equal sinks. Figure 1-5 depicts the sources included in the AB 32 GHG Inventory and the new sources and sinks added in this Scoping Plan under the framework of carbon neutrality. Natural and working lands are able to sequester carbon and therefore play an increasingly important role in this framework. However, modeling for this plan shows that carbon sequestration in our natural and working lands alone will be insufficient to achieve carbon neutrality no later than 2045. Therefore, this plan also considers the role of carbon capture and sequestration, as well as biological and mechanical carbon sequestration processes that are included in the IPCC Sixth Assessment Report,[93] as necessary tools for climate change mitigation.

[93] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

**Figure 1-5: Carbon neutrality: Balancing the net flux of GHG emissions from all sources and sinks**



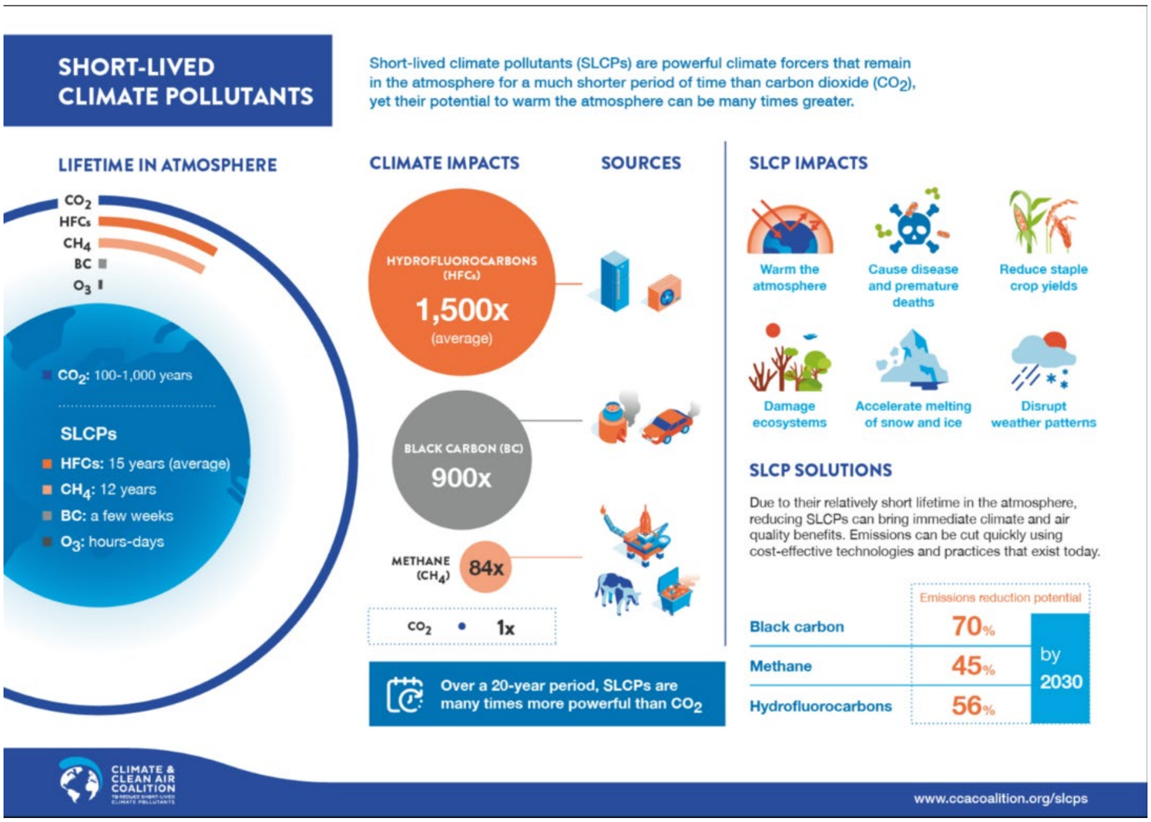

## Supporting Healthy and Resilient Lands

Our natural and working lands are an important piece in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric carbon dioxide in forests, grasslands, soils, and wetlands. Healthy lands can also reduce emissions of powerful short-lived climate pollutants, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts. Through climate smart land management that focuses on supporting healthy living systems, we can support our carbon neutrality goals, reduce emissions, advance sequestration, and support healthy and more climate-resilient lands.

## Maintaining the Focus on Methane and Short-Lived Climate Pollutants

Given the urgency of climate change, the often-disproportional impacts already being felt by underserved populations across California and the world, and the need to rapidly decarbonize and avoid climate tipping points as identified in the most recent IPCC assessment, efforts to reduce short-lived climate pollutants are especially important. SLCPs include methane ($CH_4$), black carbon (soot), and fluorinated gases (F-gases, including hydrofluorocarbons, or HFCs), and they are among the most harmful pollutants to both human health and the global climate. SLCPs are more potent than $CO_2$ in terms of their impact on climate change (and subsequently, global warming) and have a much shorter lifetime in the atmosphere than $CO_2$ does. That means they have an outsized impact on climate change in the near term—they are responsible for up to 45 percent of current climate forcing. It also means that targeted efforts to reduce short-lived climate pollutant emissions can provide outsized climate and health benefits, within weeks to about a decade (see Figure 1-6).

**Figure 1-6: Short-lived climate pollutant impacts[94]**




California has been a leader in addressing SLCP emissions. As part of the 2014 Scoping Plan,[95] CARB committed to developing a dedicated strategy to reduce SLCP emissions.

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[94] Climate and Clean Air Coalition. Short-Lived Climate Pollutants (SLCPs). https://www.ccacoalition.org/en/content/short-lived-climate-pollutants-slcps.
[95] CARB. 2014. *First Update.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

The resulting SLCP Reduction Strategy,[96] adopted by CARB in 2017, implements targets codified in SB 1383 (Lara, Chapter 395, Statutes of 2016) to reduce methane and HFC emissions by 40 percent by 2030 and anthropogenic black carbon emissions by 50 percent. California worked with several other states through the U.S. Climate Alliance to establish a similar goal to reduce SLCP emissions in line with the requirements of the Paris Agreement,[97] identifying the potential to reduce SCLPs by 40 to 50 percent by 2030 across the U.S. Climate Alliance.[98]

## Process for Developing the Scoping Plan

This Scoping Plan was developed in coordination with the Governor's Office and state agencies, in accordance with direction from the Chair and Members of CARB, through engagement with the Legislature, with advice from the EJ Advisory Committee, in consultation with tribes, and with open and transparent opportunities for stakeholders and the public to engage in workshops and other meetings. Appendix A (Public Process) includes details of the public workshops, and Chapter 5 includes details of the EJ Advisory Committee's role in the Scoping Plan update process.

### Guidance from the Administration and Legislature

This Scoping Plan reflects existing and recent direction in the Governor's Executive Orders and Statutes. Table 1-1 provides a summary of major climate legislation and executive orders issued since the adoption of the 2017 Scoping Plan.

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[96] CARB. 2017. *Short-Lived Climate Pollutant Reduction Strategy.* *https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf*.
[97] UNFCCC. 2015. Paris Agreement. *https://unfccc.int/sites/default/files/english_paris_agreement.pdf*.
[98] USCA. 2018. *From SLCP Challenge to Action: A Roadmap for Reducing Short-Lived Climate Pollutants to Meet the Goals of the Paris Agreement.* http://www.usclimatealliance.org/slcp-challenge-to-action.

**Table 1-1: Major climate legislation and executive orders enacted since the 2017 Scoping Plan**

| Bill/Executive Order | Summary |
|---|---|
| **Assembly Bill 1279 (AB 1279) (Muratsuchi, Chapter 337, Statutes of 2022)**<br><br>*The California Climate Crisis Act* | AB 1279 establishes the policy of the state to achieve carbon neutrality as soon as possible, but no later than 2045; to maintain net negative GHG emissions thereafter; and to ensure that by 2045 statewide anthropogenic GHG emissions are reduced at least 85 percent below 1990 levels. The bill requires CARB to ensure that Scoping Plan updates identify and recommend measures to achieve carbon neutrality, and to identify and implement policies and strategies that enable $CO_2$ removal solutions and carbon capture, utilization, and storage (CCUS) technologies.<br><br>This bill is reflected directly in this Scoping Plan. |
| **Senate Bill 905 (SB 905) (Caballero, Chapter 359, Statutes of 2022)**<br><br>*Carbon Capture, Removal, Utilization, and Storage Program* | SB 905 requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program to evaluate, demonstrate, and regulate CCUS and carbon dioxide removal (CDR) projects and technology.<br><br>The bill requires CARB, on or before January 1, 2025, to adopt regulations creating a unified state permitting application for approval of CCUS and CDR projects. The bill also requires the Secretary of the Natural Resources Agency to publish a framework for governing agreements for two or more tracts of land overlying the same geologic storage reservoir for the purposes of a carbon sequestration project.<br><br>The Scoping Plan modeling reflects both CCUS and CDR contributions to achieve carbon neutrality. |
| **Senate Bill 846 (SB 846) (Dodd, Chapter 239, Statutes of 2022)**<br><br>*Diablo Canyon Powerplant: Extension of Operations* | SB 846 extends the Diablo Canyon Power Plant's sunset date by up to five additional years for each of its two units and seeks to make the nuclear power plant eligible for federal loans. The bill requires that the California Public Utilities Commission (CPUC) not include and disallow a load-serving entity from including in their adopted resource plan, the energy, capacity, or any attribute from the Diablo Canyon power plant.<br><br>The Scoping Plan explains the emissions impact of this legislation. |
| **Senate Bill 1020 (SB 1020) (Laird,** | SB 1020 adds interim renewable energy and zero carbon energy retail sales of electricity targets to California end-use customers set at 90 percent in 2035 and 95 percent in 2040. |

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| **Chapter 361, Statutes of 2022)**<br><br>*Clean Energy, Jobs, and Affordability Act of 2022* | It accelerates the timeline required to have 100 percent renewable energy and zero carbon energy procured to serve state agencies from the original target year of 2045 to 2035. This bill requires each state agency to individually achieve the 100 percent goal by 2035 with specified requirements. This bill requires the CPUC, California Energy Commission (CEC), and CARB, on or before December 1, 2023, and annually thereafter, to issue a joint reliability progress report that reviews system and local reliability.<br><br>The bill also modifies the requirement for CARB to hold a portion of its Scoping Plan workshops in regions of the state with the most significant exposure to air pollutants by further specifying that this includes communities with minority populations or low-income communities in areas designated as being in extreme federal non-attainment.<br><br>The Scoping Plan describes the implications of this legislation on emissions. |
| **Senate Bill 1137 (SB 1137) (Gonzales, Chapter 365, Statutes of 2022)**<br><br>*Oil & Gas Operations: Location Restrictions: Notice of Intention: Health protection zone: Sensitive receptors* | SB 1137 prohibits the development of new oil and gas wells or infrastructure in health protection zones, as defined, except for purposes of public health and safety or other limited exceptions. The bill requires operators of existing oil and gas wells or infrastructure within health protection zones to undertake specified monitoring, public notice, and nuisance requirements. The bill requires CARB to consult and concur with the California Geologic Energy Management Division (CalGEM) on leak detection and repair plans for these facilities, adopt regulations as necessary to implement emission detection system standards, and collaborate with CalGEM on public access to emissions detection data. |
| **Senate Bill 1075 (SB 1075) (Skinner, Chapter 363, Statutes of 2022)**<br><br>*Hydrogen: Green Hydrogen: Emissions of Greenhouse Gases* | SB 1075 requires CARB, by June 1, 2024, to prepare an evaluation that includes: policy recommendations regarding the use of hydrogen, and specifically the use of green hydrogen, in California; a description of strategies supporting hydrogen infrastructure, including identifying policies that promote the reduction of GHGs and short-lived climate pollutants; a description of other forms of hydrogen to achieve emission reductions; an analysis of curtailed electricity; an estimate of GHG and emission reductions that could be achieved through deployment of green hydrogen through a variety of scenarios; an analysis of the potential for opportunities to integrate hydrogen production and applications with drinking water supply treatment needs; policy recommendations for regulatory and permitting processes |

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| | associated with transmitting and distributing hydrogen from production sites to end uses; an analysis of the life-cycle GHG emissions from various forms of hydrogen production; and an analysis of air pollution and other environmental impacts from hydrogen distribution and end uses.<br><br>This bill would inform the production of hydrogen at the scale called for in this Scoping Plan. |
| **Assembly Bill 1757 (AB 1757) (Garcia, Chapter 341, Statutes of 2022)**<br><br>*California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands* | AB 1757 requires the California Natural Resources Agency (CNRA), in collaboration with CARB, other state agencies, and an expert advisory committee, to determine a range of targets for natural carbon sequestration, and for nature-based climate solutions, that reduce GHG emissions in 2030, 2038, and 2045 by January 1, 2024. These targets must support state goals to achieve carbon neutrality and foster climate adaptation and resilience.<br><br>This bill also requires CARB to develop standard methods for state agencies to consistently track GHG emissions and reductions, carbon sequestration, and additional benefits from natural and working lands over time. These methods will account for GHG emissions reductions of $CO_2$, methane, and nitrous oxide related to natural and working lands and the potential impacts of climate change on the ability to reduce GHG emissions and sequester carbon from natural and working lands, where feasible.<br><br>This Scoping Plan describes the next steps and implications of this legislation for the natural and working lands sector. |
| **Senate Bill 1206 (SB 1206) (Skinner, Chapter 884, Statutes of 2022)**<br><br>*Hydrofluorocarbon gases: sale or distribution* | SB 1206 mandates a stepped sales prohibition on newly produced high- global warming potential (GWP) HFCs to transition California's economy toward recycled and reclaimed HFCs for servicing existing HFC-based equipment. Additionally, SB 1206 also requires CARB to develop regulations to increase the adoption of very low-, i.e., GWP < 10, and no-GWP technologies in sectors that currently rely on higher-GWP HFCs. |
| **Senate Bill 27 (SB 27) (Skinner, Chapter 237, Statutes of 2021)** | SB 27 requires CNRA, in coordination with other state agencies, to establish the Natural and Working Lands Climate Smart Strategy by July 1, 2023. This bill also requires CARB to establish specified $CO_2$ removal targets for 2030 and beyond as part of its Scoping Plan. Under SB 27, CNRA is to establish and maintain a registry to identify projects in the state |

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| *Carbon Sequestration: State Goals: Natural and Working Lands: Registry of Projects* | that drive climate action on natural and working lands and are seeking funding.<br><br>CNRA also must track carbon removal and GHG emission reduction benefits derived from projects funded through the registry.<br><br>This bill is reflected directly in this Scoping Plan as $CO_2$ removal targets for 2030 and 2045 in support of carbon neutrality. |
| **Senate Bill 596 (SB 596) (Becker, Chapter 246, Statutes of 2021)**<br><br>*Greenhouse Gases: Cement Sector: Net-zero Emissions Strategy* | SB 596 requires CARB, by July 1, 2023, to develop a comprehensive strategy for the state's cement sector to achieve net-zero-emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. The bill establishes an interim target of 40 percent below the 2019 average GHG intensity of cement by December 31, 2035. Under SB 596, CARB must:<br>• Define a metric for GHG intensity and establish a baseline from which to measure GHG intensity reductions.<br>• Evaluate the feasibility of the 2035 interim target (40 percent reduction in GHG intensity) by July 1, 2028.<br>• Coordinate and consult with other state agencies.<br>• Prioritize actions that leverage state and federal incentives.<br>• Evaluate measures to support market demand and financial incentives to encourage the production and use of cement with low GHG intensity.<br><br>The Scoping Plan modeling is designed to achieve these outcomes. |
| **Executive Order N-82-20** | Governor Newsom signed Executive Order N-82-20 in October 2020 to combat the climate and biodiversity crises by setting a statewide goal to conserve at least 30 percent of California's land and coastal waters by 2030. The Executive Order also instructed the CNRA, in consultation with other state agencies, to develop a Natural and Working Lands Climate Smart Strategy that serves as a framework to advance the state's carbon neutrality goal and build climate resilience. In addition to setting a statewide conservation goal, the Executive Order directed CARB to update the target for natural and working lands in support of carbon neutrality as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy. |

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| | Executive Order N-82-20 also calls on the CNRA, in consultation with other state agencies, to establish the California Biodiversity Collaborative (Collaborative). The Collaborative shall be made up of governmental partners, California Native American tribes, experts, business and community leaders, and other stakeholders from across the state. State agencies will consult the Collaborative on efforts to:<br>• Establish a baseline assessment of California's biodiversity that builds upon existing data and can be updated over time.<br>• Analyze and project the impact of climate change and other stressors in California's biodiversity.<br>• Inventory current biodiversity efforts across all sectors and highlight opportunities for additional action to preserve and enhance biodiversity.<br><br>CNRA also is tasked with advancing efforts to conserve biodiversity through various actions, such as streamlining the state's process to approve and facilitate projects related to environmental restoration and land management. The California Department of Food and Agriculture (CDFA) is directed to advance efforts to conserve biodiversity through measures such as reinvigorating populations of pollinator insects, which restore biodiversity and improve agricultural production.<br><br>The Natural and Working Lands Climate Smart Strategy informs this Scoping Plan. |
| **Executive Order N-79-20** | Governor Newsom signed Executive Order N-79-20 in September 2020 to establish targets for the transportation sector to support the state in its goal to achieve carbon neutrality by 2045. The targets established in this Executive Order are:<br>• 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035.<br>• 100 percent of medium- and heavy-duty vehicles will be zero-emission by 2045 for all operations where feasible, and by 2035 for drayage trucks.<br>• 100 percent of off-road vehicles and equipment will be zero-emission by 2035 where feasible.<br><br>The Executive Order also tasked CARB to develop and propose regulations that require increasing volumes of zero-electric passenger vehicles, medium- and heavy-duty |

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| | vehicles, drayage trucks, and off-road vehicles toward their corresponding targets of 100 percent zero-emission by 2035 or 2045, as listed above.<br><br>The Scoping Plan modeling reflects achieving these targets. |
| **Executive Order N-19-19** | Governor Newsom signed Executive Order N-19-19 in September 2019 to direct state government to redouble its efforts to reduce GHG emissions and mitigate the impacts of climate change while building a sustainable, inclusive economy. This Executive Order instructs the Department of Finance to create a Climate Investment Framework that:<br>• Includes a proactive strategy for the state's pension funds that reflects the increased risks to the economy and physical environment due to climate change.<br>• Provides a timeline and criteria to shift investments to companies and industry sectors with greater growth potential based on their focus of reducing carbon emissions and adapting to the impacts of climate change.<br>• Aligns with the fiduciary responsibilities of the California Public Employees' Retirement System, California State Teachers' Retirement System, and the University of California Retirement Program.<br><br>Executive Order N-19-19 directs the State Transportation Agency to leverage more than $5 billion in annual state transportation spending to help reverse the trend of increased fuel consumption and reduce GHG emissions associated with the transportation sector. It also calls on the Department of General Services to leverage its management and ownership of the state's 19 million square feet in managed buildings, 51,000 vehicles, and other physical assets and goods to minimize state government's carbon footprint. Finally, it tasks CARB with accelerating progress toward California's goal of five million ZEV sales by 2030 by:<br>• Developing new criteria for clean vehicle incentive programs to encourage manufacturers to produce clean, affordable cars.<br>• Proposing new strategies to increase demand in the primary and secondary markets for ZEVs.<br>• Considering strengthening existing regulations or adopting new ones to achieve the necessary GHG reductions from within the transportation sector. |

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| | The Scoping Plan modeling reflects efforts to accelerate ZEV deployment. |
| **Senate Bill 576 (SB 576) (Umberg, Chapter 374, Statutes of 2019)**<br><br>*Coastal Resources: Climate Ready Program and Coastal Climate Change Adaptation, Infrastructure and Readiness Program* | Sea level rise, combined with storm-driven waves, poses a direct risk to the state's coastal resources, including public and private real property and infrastructure. Rising marine waters threaten sensitive coastal areas, habitats, the survival of threatened and endangered species, beaches, other recreation areas, and urban waterfronts. SB 576 mandates that the Ocean Protection Council develop and implement a coastal climate adaptation, infrastructure, and readiness program to improve the climate change resiliency of California's coastal communities, infrastructure, and habitat. This bill also instructs the State Coastal Conservancy to administer the Climate Ready Program, which addresses the impacts and potential impacts of climate change on resources within the conservancy's jurisdiction. |
| **Assembly Bill 65 (AB 65) (Petrie-Norris, Chapter 347, Statutes of 2019)**<br><br>*Coastal Protection: Climate Adaption: Project Prioritization: Natural Infrastructure: Local General Plans* | This bill requires the State Coastal Conservancy, when it allocates any funding appropriated pursuant to the California Drought, Water, Parks, Climate, Coastal Protection, and Outdoor Access For All Act of 2018, to prioritize projects that use natural infrastructure in coastal communities to help adapt to climate change. The bill requires the conservancy to provide information to the Office of Planning and Research on any projects funded pursuant to the above provision to be considered for inclusion into the clearinghouse for climate adaption information. The bill authorizes the conservancy to provide technical assistance to coastal communities to better assist them with their projects that use natural infrastructure. |
| **Executive Order B-55-18** | Governor Brown signed Executive Order B-55-18 in September 2018 to establish a statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, and to achieve and maintain net negative emissions thereafter. Policies and programs undertaken to achieve this goal shall:<br>• Seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities.<br>• Be implemented in a manner that supports climate adaptation and biodiversity, including protection of the state's water supply, water quality, and native plants and animals. |

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| | This Executive Order also calls for CARB to:<br>• Develop a framework for implementation and accounting that tracks progress toward this goal.<br>• Ensure future Scoping Plans identify and recommend measures to achieve the carbon neutrality goal.<br><br>This Scoping Plan is designed to achieve carbon neutrality no later than 2045 and the modeling includes technology and fuel transitions to achieve that outcome. |
| **Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018)**<br><br>*California Renewables Portfolio Standard Program: emissions of greenhouse gases* | SB 100 mandates that the CPUC, CEC, and CARB plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045. This bill also updates the state's Renewables Portfolio Standard (RPS) to include the following interim targets:<br>• 44% of retail sales procured from eligible renewable sources by December 31, 2024.<br>• 52% of retail sales procured from eligible renewable sources by December 31, 2027.<br>• 60% of retail sales procured from eligible renewable sources by December 31, 2030.<br><br>Under SB 100, the CPUC, CEC, and CARB shall use programs under existing laws to achieve 100 percent clean electricity. The statute requires these agencies to issue a joint policy report on SB 100 every four years. The first of these reports was issued in 2021.<br><br>This Scoping Plan reflects the SB 100 Core Scenario resource mix with a few minor updates. |
| **Assembly Bill 2127 (AB 2127) (Ting, Chapter 365, Statutes of 2018)**<br><br>*Electric Vehicle Charging Infrastructure: Assessment* | This bill requires the CEC, working with CARB and the CPUC, to prepare and biennially update a statewide assessment of the electric vehicle charging infrastructure needed to support the levels of electric vehicle adoption required for the state to meet its goals of putting at least 5 million zero-emission vehicles on California roads by 2030 and of reducing emissions of GHGs to 40% below 1990 levels by 2030. The bill requires the CEC to regularly seek data and input from stakeholders relating to electric vehicle charging infrastructure.<br><br>This bill supports the deployment of ZEVs as modeled in this Scoping Plan. |

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| **Senate Bill 30 (SB 30) (Lara, Chapter 614, Statutes of 2018)**<br><br>*Insurance: Climate Change* | This bill requires the Insurance Commissioner to convene a working group to identify, assess, and recommend risk transfer market mechanisms that, among other things, promote investment in natural infrastructure to reduce the risks of climate change related to catastrophic events, create incentives for investment in natural infrastructure to reduce risks to communities, and provide mitigation incentives for private investment in natural lands to lessen exposure and reduce climate risks to public safety, property, utilities, and infrastructure. The bill requires the policies recommended to address specified questions. |
| **Assembly Bill 2061 (AB 2061) (Frazier, Chapter 580, Statutes of 2018)**<br><br>*Near-zero-emission and Zero-emission Vehicles* | Existing state and federal law sets specified limits on the total gross weight imposed on the highway by a vehicle with any group of two or more consecutive axles. Under existing federal law, the maximum gross vehicle weight of that vehicle may not exceed 82,000 pounds. AB 2061 authorizes a near-zero-emission vehicle or a zero-emission vehicle to exceed the weight limits on the power unit by up to 2,000 pounds.<br><br>This bill supports the deployment of cleaner trucks as modeled in this Scoping Plan. |

## Consideration of Relevant State Plans and Regulations

Development of this Scoping Plan also included careful consideration of, and coordination with, other state agency plans and regulations, including the SB 100 Joint Agency Report,[99] the 2022 State Strategy for the State Implementation Plan,[100] Climate Action Plan for Transportation Infrastructure,[101] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[102,103,104] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[105]

[99] CPUC, CEC, and CARB. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100.
[100] CARB. January 31, 2022. Draft 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf.
[101] CalSTA. 2021. *Climate Action Plan.* https://calsta.ca.gov/subject-areas/climate-action-plan.
[102] CalEPA. 2021. Carbon Neutrality Studies. https://calepa.ca.gov/climate/carbon-neutrality-studies/.
[103] Brown, A. L., et. al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0.
[104] Deschenes, O. 2021. *Enhancing equity*. https://zenodo.org/record/4707966#.YKPiaKhKi73.
[105] CARB. Short-Lived Climate Pollutants. https://ww2.arb.ca.gov/our-work/programs/slcp.

CARB's Achieving Carbon Neutrality Report,[106] Climate Smart Strategy,[107] and draft Natural and Working Lands Implementation Plan,[108] among others.

### Input from Partners and Stakeholders

CARB also collaborated with other state agencies, held consultations with tribes, and solicited comments and feedback from affected stakeholders, including labor organizations and the public. The process to update the Scoping Plan began with kickoff workshops in early June 2021,[109] followed by over a dozen public workshops, including engagement with tribes,[110] and featured a series of EJ Advisory Committee and environmental justice community meetings.[111] The June 2021 workshop and several others were a joint agency effort, as there are many agencies with direct authority or jurisdiction over different sectors of the economy. Consultation with agencies also included bi-weekly, monthly, and weekly meetings.

During the summer of 2022 CARB held three community listening sessions, hosted by the CARB Chair and Board, in communities around the state, along with one virtual community listening session and one tribal listening session specifically for tribes. Many tribes provided written feedback, which was incorporated into this Scoping Plan. In addition, CARB respects tribal sovereignty and also engaged in a consultation campaign with tribes, which resulted in government-to-government consultations, and this Scoping Plan is reflective of this process.[112]

## Emissions Data That Inform the Scoping Plan

### Greenhouse Gas Emissions

AB 32 includes which GHGs are to be regulated, reduced, and included in the state's targets and goals. That list includes seven GHGs: carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), sulfur hexafluoride ($SF_6$), hydrofluorocarbons (HFCs),

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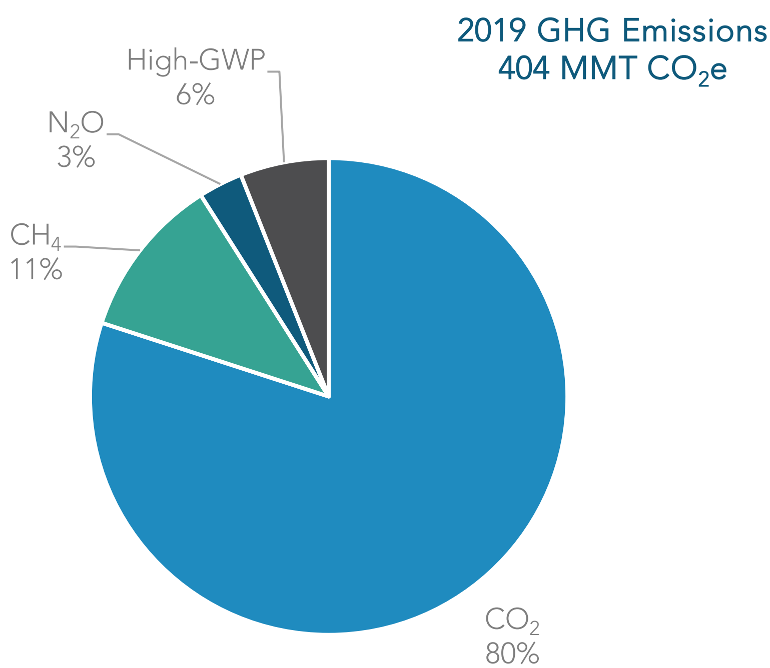
[106] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.
[107] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/Initiatives/Expanding-Nature-Based-Solutions.
[108] CARB. 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.* https://ww2.arb.ca.gov/resources/documents/nwl-implementation-draft.
[109] Appendix A (Public Process).
[110] CARB. Scoping Plan Meetings & Workshops. https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops.
[111] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.
[112] CARB. 2018. Tribal Consultation Policy. October. https://www.arb.ca.gov/regact/nonreg/2018/california_air_resources_board_tribal_consultation_policy.pdf.

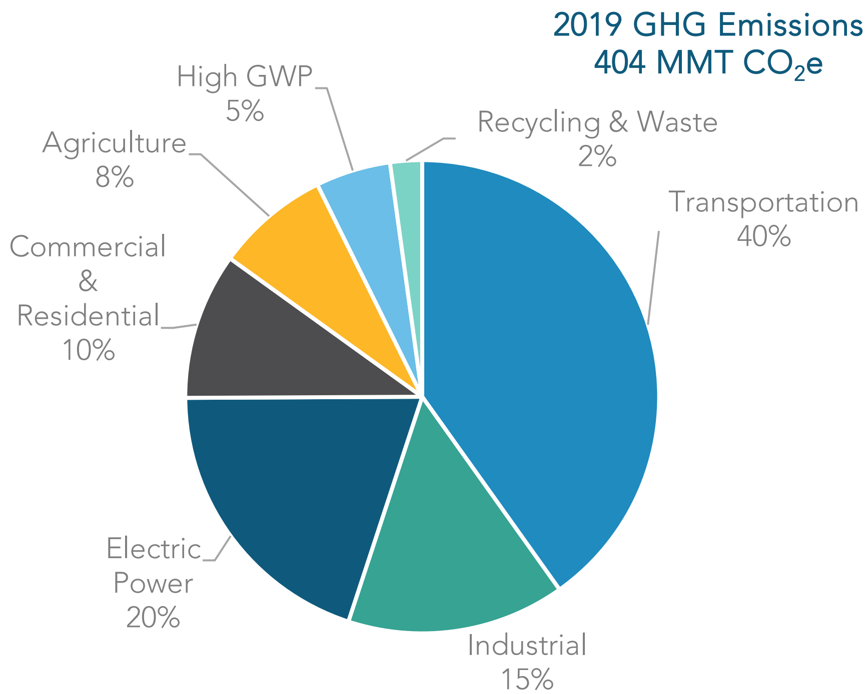
perfluorocarbons (PFCs), and nitrogen trifluoride ($NF_3$). Carbon dioxide is the primary GHG emitted in California, accounting for 83 percent of the total GHG emissions in 2019, as shown in Figure 1-7 below. Figure 1-8 illustrates that transportation (primarily on-road travel) is the single largest source of $CO_2$ emissions in the state. Upstream transportation emissions from the refinery and oil and gas sectors are categorized as $CO_2$ emissions from industrial sources and constitute about 50 percent of the industrial source emissions. When including these emissions, the transportation sector accounts for approximately half of statewide GHG emissions. Other significant sources of $CO_2$ include electricity production, industrial sources like refineries and cement plants, and residential sources like fossil gas. Figures 1-7 and 1-8 show state GHG emission contributions by GHG and sector based on the 2020 Greenhouse Gas Emission Inventory; GHG emissions for 2019 are shown because 2020 was an outlier due to the global pandemic. Emissions in Figure 1-8 are depicted by Scoping Plan sector, which includes separate categories for high-global warming potential (GWP) and recycling/waste emissions that are otherwise typically included within other economic sectors.

**Figure 1-7: 2019 State GHG emission contributions by GHG[113]**




[113] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

**Figure 1-8: 2019 State GHG emission contributions by Scoping Plan sector**[114]




The scope of the AB 32 GHG Inventory encompasses emission sources within the state's borders, as well as imported electricity consumed in the state. This construct for the inventory is consistent with IPCC practices to allow for comparison of statewide GHG emissions with those at the national level and with other international GHG inventories. Statewide GHG emissions calculations use many data sources, including data from other state and federal agencies. However, a significant source of data comes from reports submitted to CARB through the Regulation for the Mandatory Reporting of GHG Emissions (MRR). The MRR requires facilities and entities with more than 10,000 metric tons of carbon dioxide equivalent ($MTCO_2e$) of combustion and process emissions, all facilities belonging to certain industries, and all electric power entities to submit an annual GHG emissions data report directly to CARB. Furthermore, this regulation requires that reports from entities that emit more than 25,000 $MTCO_2e$ be verified by a CARB-

[114] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, $SF_6$ emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily HFCs, are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

accredited third-party verification body. More information on MRR emissions reports can be found at CARB's Mandatory Greenhouse Gas Emissions Reporting website.[115]

All data sources used to develop the GHG Emission Inventory are listed in CARB's inventory supporting documentation.[116]

## Natural and Working Lands

For natural and working lands, the 2018 ecosystem carbon inventory (NWL Inventory)[117] shows there are approximately 5,340 million metric tons (MMT) of carbon in the carbon pools[118] (reservoirs of carbon that have the ability to both take in and release carbon) that CARB has quantified (see Figure 1-9). For purposes of comparison, 5,340 MMT of ecosystem carbon stock is equivalent to 19,600 MMT of atmospheric $CO_2$. Forests and shrublands contain the majority of California's carbon stock because they cover the majority of California's landscape and have the highest carbon density of any land cover type. All other land categories combined comprise over 35 percent of California's total acreage, but only 15 percent of carbon stocks. Roughly half of the 5,340 MMT of carbon resides in soils and half in plant biomass.

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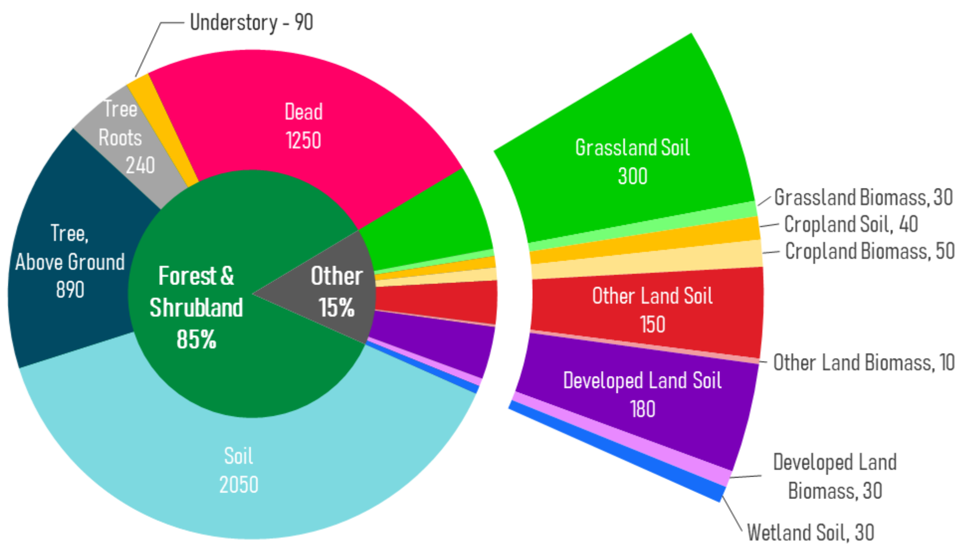
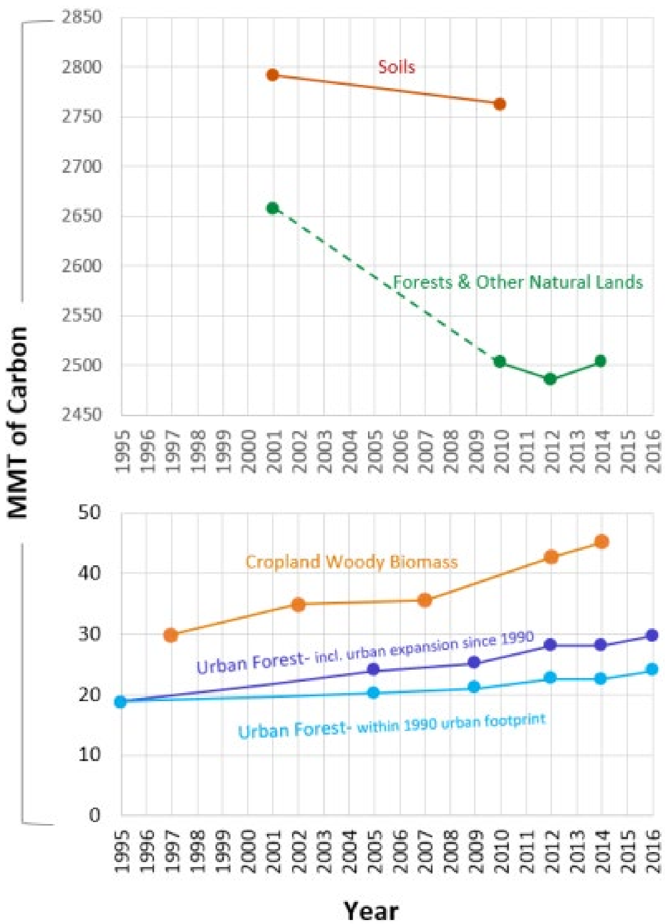
[115] CARB. Mandatory Greenhouse Gas Emissions Reporting. https://ww2.arb.ca.gov/our-work/programs/mandatory-greenhouse-gas-emissions-reporting.
[116] CARB. Current California GHG Emission Inventory Data. www.arb.ca.gov/cc/inventory/data/data.htm.
[117] CARB. 2018. *An Inventory of Ecosystem Carbon in California's Natural and Working Lands.* https://ww3.arb.ca.gov/cc/inventory/pubs/nwl_inventory.pdf.
[118] "Carbon pools" are Above-Ground Live Biomass (boles, stems, and foliage in shrubs, trees, grasses, and herbaceous vegetation), Below-Ground Live Biomass (roots in shrubs, trees, grasses, and herbaceous vegetation), Dead Organic Matter (standing or downed dead wood and litter), Harvested Wood Products (all wood and bark material that leaves harvest sites regardless of whether it is eventually incorporated into merchandisable products), and Soil Organic Matter (organic carbon in the top 30 centimeters of soil).

**Figure 1-9: Carbon stocks in natural and working lands (MMT carbon)**




In addition to providing an estimate of the ecosystem carbon that exists on California's landscape, the NWL Inventory also shows how those carbon stocks are changing (see Figure 1-10). The inventory attributes stock change to human activity, such as land use change, or to disturbances, such as wildfire. CARB's inventory shows these lands were a source of GHG emissions from 2001 to 2011, releasing more carbon than they stored, and then they returned to be a slight carbon sink from 2012 to 2014. These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon.

**Figure 1-10: Changes in carbon stock by landscape type**




For natural and working lands, California's inventory is also based on IPCC methods for tracking ecosystem carbon over time, providing for comparability with other national and subnational inventories and carbon accounting. As such, the NWL Inventory is an important tool for tracking both carbon stock changes in California over time and the impacts that interventions such as those identified in this Scoping Plan, actions identified in the Climate Smart Land Strategy, and others have on NWL carbon stocks.

All data sources used to develop the NWL Inventory are listed in the technical support documentation at CARB's California Natural & Working Lands Inventory website.[119]

[119] CARB. California Natural & Working Lands Inventory. https://ww2.arb.ca.gov/nwl-inventory.

## Black Carbon

In addition, CARB has developed a statewide emission inventory for black carbon in support of the SLCP Strategy. The inventory is reported in two categories: non-forestry (anthropogenic) sources and forestry sources.[120] The black carbon inventory is calculated using existing $PM_{2.5}$ emission inventories combined with speciation profiles that define the fraction of $PM_{2.5}$ that is black carbon. The black carbon inventory helps support implementation of the SLCP Strategy, but it is not part of California's GHG Inventory that tracks progress toward the state's climate targets under AB 32 or SB 32. The state's major anthropogenic sources of black carbon include off-road transportation, on-road transportation, residential wood burning, fuel combustion, and industrial processes. CARB estimated 2017 black carbon emissions to be approximately 8 $MTCO_2e$.[121] The majority of anthropogenic sources come from transportation—specifically, heavy-duty vehicles. The share of black carbon emissions from transportation is dropping rapidly and is expected to continue to do so between now and 2030 as a result of California's air quality programs. The remaining black carbon emissions will come largely from woodstoves/fireplaces, off-road applications, and industrial/commercial combustion. The forestry category includes non-agricultural prescribed burning and wildfire emissions.

## Tracking Life-Cycle and Out-of-State Emissions

In recent years there has been increased interest in the embedded carbon in products, also known as *life-cycle emissions.* A life-cycle accounting framework refers to all of the GHG emissions generated from the sourcing, production, and transportation of products to an endpoint. In doing such assessments for a product, emissions may be associated with sourced materials and production activity outside a jurisdiction's borders. While life-cycle emissions can provide a more comprehensive picture of the emissions associated with the goods we consume and ongoing demand, life-cycle inventories are inconsistent with IPCC standards, as they would result in double counting of emissions across jurisdictions. Other countries and regions do produce their own inventory reports consistent with IPCC methods and are taking action to reduce emissions within their jurisdictions. In addition, jurisdictions often lack legal authority to regulate sources outside of their borders. Finally, it is difficult to obtain accurate data for sources and production activities outside of a region's border that would impact the accuracy of such an inventory. For these reasons, the inventory used in the Scoping Plan does not use a life-cycle

[120] SB 1383. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.
[121] This is a preliminary estimate developed for this Scoping Plan. Official Black Carbon emissions estimates are provided in the SLCP inventory here: https://ww2.arb.ca.gov/ghg-slcp-inventory.

approach and remains consistent with international accounting standards and consistent with how other countries and regions track emissions within their jurisdictions.

However, GHG mitigation action may cross geographic borders as part of subnational and international collaboration, or as a natural result of implementation of regional policies. In addition to the state's existing GHG inventory, CARB will develop an accounting framework that reflects the benefits of our policies accruing outside of the state. This accounting framework will be important to better understand the true impact of the state's policies on what is emitted into the atmosphere. For example, the LCFS incentivizes GHG reductions along the entire supply chain for the production and delivery of transportation fuel imported for use in the state. However, our inventory only captures the change in emissions from the tailpipe of when that fuel is used in California and does not capture any GHG reductions that occur in the production process if the fuel is produced out of state.

Natural and working lands forestry actions are another example, where California's policies are inspiring forest management actions in other states that result in increased permanent carbon sequestration. California's NWL inventory does not capture the increased carbon stocks resulting from forestry projects happening outside of California, and the $CO_2$ removals resulting from these projects are not applied in either CARB's NWL inventory or CARB's AB 32 GHG Emissions Inventory. For GHG reductions outside of the state to be attributed to our programs, those reductions must be real, quantifiable, verifiable, and permanent.

It also will be important to avoid any double counting (including claims to those reductions by other jurisdictions) and to transparently indicate whether any extra-jurisdictional emissions reductions might be included in another region's inventory. CARB is collaborating with other jurisdictions to ensure GHG accounting rules are consistent with international best practices, as robust accounting rules instill confidence in the reductions claimed and maintain support for joint action across jurisdictions. The policy goals of consistency and transparency are critical as we work together with other jurisdictions on our parallel paths to achieve our GHG targets with real benefits to the atmosphere.

## Tracking Progress

Historically, the AB 32 GHG Inventory has been the primary metric to track progress toward achieving climate targets.[122] However, we must now deploy clean technology at unprecedented rates. The emissions modeling underpinning this Scoping Plan and

[122] Starting with the 2022 Edition of the AB 32 GHG inventory, the inventory development now relies more directly on the annually reported and third-party verified emissions from the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

targets for clean technology in statute can serve as leading indicators across the economy on how our actions compare to the pace of action needed to be on track to achieve carbon neutrality. The California Climate Dashboard[123] was launched in 2022 and provides high-level metrics for clean energy production and technology deployment. Statistics such as the deployment of zero emission vehicles and clean electricity generation are just some of the examples of metrics across the economy that can be tracked, in addition to GHG emissions, to understand if the state is on track to meet its climate goals. A key indicator to track will be building of new energy infrastructure and deployment of clean technology as evaluated in the uncertainty analysis in Chapter 2. CARB will coordinate with state agencies to establish and make public similar metrics across all economic sectors to help provide transparency on the state's progress in deploying clean technology at the pace and scale needed to achieve carbon neutrality no later than 2045.

[123] CalEPA. California Climate Dashboard. https://calepa.ca.gov/climate-dashboard/.

# Chapter 2: The Scoping Plan Scenario

This chapter describes the Scoping Plan Scenario, which for the first time includes sources in both the AB 32 GHG Inventory and Natural and Working Lands (NWL). It begins with a short description of the alternatives evaluated. Four scenarios for the AB 32 GHG Inventory and NWL were considered separately and helped to inform the Scoping Plan Scenario. Each of the alternatives were considered in terms of the important criteria and priorities that the state's comprehensive climate action must deliver, including the need for GHG reductions that are not only technologically feasible and cost-effective, but also can deliver health and economic benefits for the state. All the scenarios were set against what is called the *Reference Scenario*—that is, what the GHG emissions would look like if we did nothing at all beyond the existing policies that are required and already in place to achieve the 2030 target of at least 40 percent below 1990 levels, or those expected with no new actions in the NWL sector. For this Scoping Plan, two sets of modeling tools were used to evaluate the AB 32 GHG Inventory and NWL sectors because no single model can assess both AB 32 sectors and NWL together. As a result, two different sets of scenarios were developed for each sector type. While this chapter breaks out discussion separately for the two sector types, the Scoping Plan Scenario reflects the combined actions across both sectors by choosing an alternative from each sector type. The modeling provides point estimates; however, that does not imply precision. As discussed in the uncertainty section, several types of uncertainties are associated with any outcomes projected by the modeling results. There will be ranges of estimates associated with each point that are not shown in the graphs or results.

## Scenarios for the AB 32 GHG Inventory Sectors

The Reference Scenario for the AB 32 GHG Inventory sectors shows continuing but modest GHG reductions beyond 2030 that level off toward mid-century. The comprehensive analysis of all four alternatives indicates that the Scoping Plan Scenario is the best choice to achieve California's climate and clean air goals while balancing the legislative direction on prioritizing direct emissions reductions, reducing anthropogenic emissions by at least 85 percent by 2045, being technologically feasible, and being cost-effective. It also protects public health, provides a solid foundation for continued economic growth, and drastically reduces the state's dependence on fossil fuel combustion and does not disproportionately impact disadvantaged communities. Each of the alternative scenarios was the product of a process of development informed by public input, the governor,[124] CARB, legislative direction, and input by the EJ Advisory Committee.[125, 126] Future updates to the Scoping Plan may consider new clean technologies and fuels beyond those included in this Scoping Plan.

The four scenarios evaluated shared many similarities. They each embodied the following characteristics:

- Drastic reduction in fossil fuel dependence, with some remaining in-state demand for fossil fuels for aviation, marine, and locomotion applications, and for fossil gas for buildings and industry
- Ambitious deployment of efficient non-combustion technologies such as zero emission vehicles and heat pumps
- Rapid growth in the production and distribution of clean energy such as zero carbon electricity and hydrogen
- Progressive phasedown of fossil fuel production and distribution activities as part of the transition to clean energy
- Remaining emissions of fugitive SLCPs such as refrigerants and fugitive methane
- Strong consumer adoption of clean technology and fuel options
- Removal of remaining $CO_2$ emissions to achieve carbon neutrality
- Some reliance on carbon capture and sequestration (CCS)

While the four scenarios had a lot in common, they also had some differences:

- Year in which carbon neutrality is achieved (2035 or 2045)
- Rate of deployment of clean technology and production and distribution of zero carbon energy
- Remaining amount of demand for fossil energy in the year carbon neutrality is achieved
- Constraints on technology and fuels deployed in certain sectors
- Consumer adoption rates of clean technologies and fuels
- Degree of reliance on $CO_2$ removal
- Degree of reliance on CCS

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[124] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. Retrieved from *https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf*.

[125] EJ Advisory Committee. December 2, 2021. EJ Advisory Committee Responses for the CARB Scenario Inputs. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf*.

[126] CARB. January 25, 2022. Update on PATHWAYS Scenario Modeling Assumptions. *https://ww2.arb.ca.gov/sites/default/files/2022-01/Scenario%20Slides%20for%20Jan25%20EJAC%20Mtg_01242022.pdf*.

The summary below provides an overview of the alternatives designed and considered for the energy and industrial sectors in this update. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*

**Scoping Plan Scenario (modeling scenario Alternative 3 from the Draft):** carbon neutrality by 2045, deploy a broad portfolio of existing and emerging fossil fuel alternatives and clean technologies, and align with statutes, Executive Orders, Board direction, and direction from the governor

**Alternative 1:** carbon neutrality by 2035, nearly complete phaseout of all combustion, limited reliance on carbon capture and sequestration and engineered carbon removal, and restricted applications for biomass-derived fuels

**Alternative 2:** carbon neutrality by 2035 and aggressive deployment of a full suite of technology and energy options, including engineered carbon removal

**Alternative 4:** carbon neutrality by 2045, deployment of a broad portfolio of existing and emerging fossil fuel alternatives, slower deployment and adoption rates than the Scoping Plan Scenario, and a higher reliance on $CO_2$ removal

Other considerations for the AB 32 GHG Inventory sectors include the following:

- To what extent does an alternative meet the statewide targets and any sector targets, and also deliver clean air benefits (especially in the near term) to address ongoing healthy air disparities, prioritize reductions for mobile and large stationary sources, and emphasize continued investment in disadvantaged communities?
- Does an alternative support California in building on efforts to collaborate with other jurisdictions and include exportable policies based on robust science?
- Does an alternative provide for compliance options and a cost-effective approach to reduce GHG emissions?
- Does the alternative present a realistic and ambitious path forward consistent with statute and science, and support economic opportunities, particularly in anticipated growth sectors?

## Scenarios for Natural and Working Lands

For the natural and working lands sector, the Reference Scenario shows that NWL will continue to emit GHGs and lose carbon stocks into the future as the combined effects of past unhealthy management practices and climate change impact our lands. Relative to the Reference Scenario, the four NWL scenarios represent different scales of land management on seven landscapes (forests, shrublands/chaparral, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands) to support carbon neutrality.

The analysis of the four NWL scenarios shows that the Scoping Plan Scenario is the preferred choice because it prioritizes sustainable land management to sequester carbon over the long term, GHG and air pollution reductions, ecosystem health and resilience, and implementation and technological feasibility and cost-effectiveness. The Scoping Plan Scenario reduces catastrophic wildfire risk to the state; increases the health and resilience of California's forests, shrublands, and grasslands; increases soil health; and protects, restores, and enhances California's natural and working lands for future generations. The Scoping Plan Scenario takes into consideration the priority landscapes and nature-based strategies identified in California's Climate Smart Strategy[127] and reflects the state's priorities to manage lands in ways that support the multiple benefits they provide. The Scoping Plan Scenario, as well as each of the alternative NWL scenarios, were informed by input from other agencies, the public, and the EJ Advisory Committee. Additional landscapes and land management activities will be added and evaluated in future Scoping Plan updates and in response to AB 1757.

Each of the NWL scenarios have several similarities, including the following:

- Prioritizing NWL management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. These actions can reduce GHG emissions from these lands, protect ecosystems against future climate change, protect communities, and enhance the ecosystem benefits they provide to nature and society.
- Exploring the potential impacts of different levels of NWL management actions that are designed to achieve the objective associated with each scenario.
- Analyzing the carbon impacts of land management actions, climate change, wildfire, and water use on California's diverse natural and working lands through 2045.

There are also differences across the four NWL scenarios. These include:

- The level of NWL management actions taken on each landscape, such as varying the acres of healthy soils practices for croplands.
- The types of NWL management actions taken on each landscape, such as prescribed burning or thinning for forests, grasslands, and shrublands.

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[127] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

The summary below provides an overview of the alternatives designed and considered for the NWL sectors in this Scoping Plan. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*.

> **Scoping Plan Scenario (NWL Alternative 3 from the Draft):** land management activities that prioritize restoration and enhancement of ecosystem functions to improve resilience to climate change impacts, including more stable carbon stocks
>
> **NWL Alternative 1:** land management activities that prioritize short term carbon stocks in our forests and through increased climate smart agricultural practices on croplands
>
> **NWL Alternative 2:** land management activities representative of California's current commitments and plans
>
> **NWL Alternative 4:** land management activities that prioritize reducing catastrophic wildfires in forests, shrublands, and grasslands

## Evaluation of Scoping Plan Alternatives

CARB staff solicited feedback from topical experts, affected stakeholders, and the EJ Advisory Committee, including a tribal representative, at public meetings to assemble input assumptions for four carbon neutrality scenarios to model using PATHWAYS. Revisions to the Draft Scoping Plan were informed by direction in statute, the Governor's Executive Orders, public comments, and the recommendations of the EJ Advisory Committee. The three alternative scenarios were designed to explore the potential speed, magnitude, and impacts of transitioning California's energy demand away from fossil fuels. The modeling assumptions listed below identify the primary fossil fuel alternative that is commercially available and technically feasible for widespread use by 2045 for each sector. CARB assumes that any energy demand that remains after the alternative technology or fuel is applied—such as on-road internal combustion engines, industrial processes, and gas use in existing buildings that have not yet decarbonized—will continue to be met by fossil fuels, resulting in residual GHG emissions.

## NWL Scoping Plan Alternatives

For the NWL sectors, staff significantly expanded the scale of the scientific analysis for NWL from previous Scoping Plan efforts. CARB staff utilized modeling tools for this expanded analysis to assess both the carbon and other ecological, public health, and economic outcomes of management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. CARB staff aligned the scenarios with both the landscape types and actions identified in other efforts called for in Governor Newsom's Executive Order N-82-20 (e.g., California's Climate Smart Strategy and Pathways to 30x30). As part of this Scoping Plan, CARB staff modeled as many of the management actions identified in the Natural and Working Lands Climate

Smart Strategy as were feasible. The management actions that were included in the model were selected because of the State of California's previous work to quantify these actions' impacts. It was not feasible to model every land management strategy for NWL, and so it is possible that larger volumes of sequestration (e.g., in soils or in oceans) could result from additional non-modeled activities. California's Natural and Working Lands Climate Smart Strategy includes a more comprehensive listing of priority nature-based solutions and management actions. It is important to note that the absence of a particular management action or its climate benefit in the modeling is not an indication of its importance or potential contributions toward meeting the target or toward supporting the carbon neutrality target for California.

**Forests:** Management strategies were modeled for forests: biological/chemical/ herbaceous treatments (e.g., herbicide application), clearcut, various timber harvests (e.g., variable retention, seed tree / shelterwood, selection harvesting), mastication, other mechanical treatments (e.g., piling of dead material, understory thinning), prescribed burning, and thinning. Avoided land conversion to another land use was also included in the modeling. Wildfire was modeled and is responsive to management strategies and climate conditions.

**Shrublands and chaparral:** Management strategies were modeled for shrublands and chaparral: biological/chemical/herbaceous treatments, prescribed burning, mechanical treatment (e.g., mastication, crushing, mowing, piling), and avoided conversion from shrubland to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

**Grasslands:** Management strategies were modeled for grasslands: biological/chemical/herbaceous treatments, prescribed burning, and avoided land conversion from grasslands to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

**Croplands:** Management strategies were modeled for row crops: cover cropping, no till, reduced till, compost amendment, transition to organic[128] farming, avoided conversion of annual crop agricultural land through easements, establishing riparian forest buffers, alley cropping, establishing windbreaks/shelterbelts, establishing tree and shrubs in croplands, and establishing hedgerows. For perennial crops, windbreaks/shelterbelts, hedgerows, conversion from annual crops to perennial crops, and avoided conversion to other land uses were modeled.

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[128] Note: $N_2O$ reductions from decreases in synthetic fertilizer application in organic farming were not modeled.

**Developed lands:** Management strategies were modeled for developed lands: Increasing tree canopy cover through planting trees and improved management of existing trees, and removing vegetation surrounding structures in accordance with the CAL FIRE Defensible Space PRC 4291.

**Wetlands:** Management strategies were modeled for wetlands: Restoring wetlands through submerging cultivated land in the Sacramento-San Joaquin Delta and avoided land conversion in the Sacramento-San Joaquin Delta.

**Sparsely vegetated lands:** Management strategies were modeled for sparsely vegetated lands: Avoided conversion of sparsely vegetated lands to another land use.

## Scoping Plan Scenario

The Scoping Plan Scenario achieves GHG emission reductions that exceed the levels expected based on existing policies represented in the Reference Scenario, keeping California on track to achieve the SB 32 GHG reduction target for 2030 and become carbon neutral no later than 2045. Actions that reduce GHG emissions and transition AB 32 GHG Inventory sources away from fossil fuel combustion affect each economic sector. Actions that lead to improved carbon stocks affect each landscape.

### AB 32 GHG Inventory Sectors

The AB 32 GHG Inventory Sector Reference scenario is the forecasted statewide GHG emissions through mid-century, with existing policies and programs but without any further action to reduce GHGs beyond those needed to achieve the 2030 limit. The Reference Scenario was developed based on other projections of business-as-usual conditions. Sources of data and policies included are:

- California Energy Demand Forecast[129]
- The two transportation carbon neutrality studies required by AB 74[130]
- The Mobile Source Strategy[131]
- SB 100 60 percent Renewables Portfolio Standard
- A Low Carbon Fuel Standard carbon intensity reduction target of 20 percent

Policies that are under study or design, such the Advanced Clean Fleets regulation, are not included. The Reference Scenario reflects current trends and expected performance of policies identified in the 2017 Scoping Plan—some of which are performing better (such as the RPS and LCFS) and others that may not meet expectations (such as vehicle miles traveled [VMT] reductions and methane capture). Figure 2-1 provides the modeling results for a Reference Scenario for the AB 32 GHG Inventory sectors compared to the Scoping Plan Scenario.

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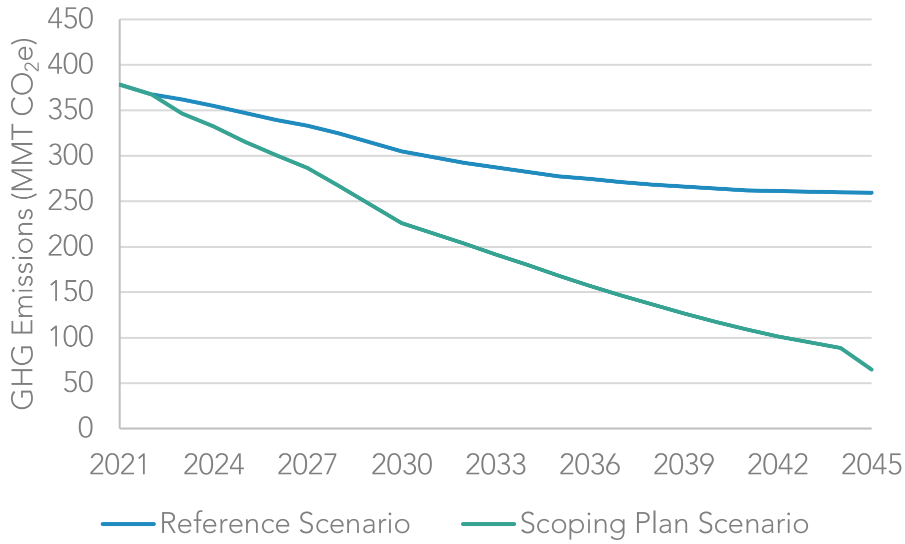
[129] California Energy Commission (CEC). 2020. *2019 Integrated Energy Policy Report.* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

[130] Brown et al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0 and Deschenes et al. 2021. *Enhancing equity.* https://zenodo.org/record/4707966#.Yl72RNrMKUn.

[131] CARB. 2021. 2020 *Mobile Source Strategy.* https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

**Figure 2-1: Reference and Scoping Plan Scenario GHG emissions[132]**




The Scoping Plan Scenario is summarized in Table 2-1. The table shows the types of technologies and energy needed to drastically reduce GHG emissions from the AB 32 Inventory sectors. It also includes references to relevant statutes and Executive Orders, although it is not comprehensive of all existing new authorities for directing or supporting the actions described. Each action is expected to both reduce GHGs and help improve air quality, primarily by transitioning away from combustion of fossil fuels. The Scoping Plan Scenario achieves the AB 1279 target of 85 percent below 1990 levels by 2045 and identifies a need to accelerate the 2030 target to 48 percent below 1990 levels.

[132] The drop in emissions in 2045 reflects both the need to achieve an 85% reduction below 1990 levels in anthropogenic emissions per AB 1279 and Governor Newsom’s request for a 100 MMT CO2e carbon removal and capture target in 2045. This was modeled by extending CCS to electric sector emissions.

**Table 2-1: Actions for the Scoping Plan Scenario: AB 32 GHG Inventory sectors**

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| GHG Emissions Reductions Relative to the SB 32 Target[133] | 40% below 1990 levels by 2030 | SB 32: Reduce statewide GHG emissions.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Smart Growth / Vehicle Miles Traveled (VMT) | VMT per capita reduced 25% below 2019 levels by 2030, and 30% below 2019 levels by 2045 | SB 375: Reduce demand for fossil transportation fuels and GHGs, and improve air quality.<br>In response to Board direction and EJ Advisory Committee recommendations |
| Light-duty Vehicle (LDV) Zero Emission Vehicles (ZEVs) | 100% of LDV sales are ZEV by 2035 | EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br>2035 target aligns with the EJ Advisory Committee recommendation. |

[133] While the SB 32 GHG emissions reduction target is not an Action that is analyzed independently, it is included in this table for reference.

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Truck ZEVs | 100% of medium-duty (MDV)/HDV sales are ZEV by 2040 (AB 74 University of California Institute of Transportation Studies [ITS] report) | EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Aviation | 20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045.<br>Sustainable aviation fuel meets most or the rest of the aviation fuel demand that has not already transitioned to hydrogen or batteries. | Reduce demand for petroleum aviation fuel and reduce GHGs.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br>In response to Governor Newsom's July 2022 letter to CARB Chair Liane Randolph |
| Ocean-going Vessels (OGV) | 2020 OGV At-Berth regulation fully implemented, with most OGVs utilizing shore power by 2027.<br>25% of OGVs utilize hydrogen fuel cell electric technology by 2045. | Reduce demand for petroleum fuels and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Port Operations | 100% of cargo handling equipment is zero-emission by 2037.<br>100% of drayage trucks are zero emission by 2035. | Executive Order N-79-20:<br>Reduce demand for petroleum fuels and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Freight and Passenger Rail | 100% of passenger and other locomotive sales are ZEV by 2030.<br><br>100% of line haul locomotive sales are ZEV by 2035.<br><br>Line haul and passenger rail rely primarily on hydrogen fuel cell technology, and others primarily utilize electricity. | Reduce demand for petroleum fuels and GHGs, and improve air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Oil and Gas Extraction | Reduce oil and gas extraction operations in line with petroleum demand by 2045. | Reduce GHGs and improve air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Petroleum Refining | CCS on majority of operations by 2030, beginning in 2028<br><br>Production reduced in line with petroleum demand. | Reduce GHGs and improve air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
| --- | --- | --- |
| Electricity Generation | Sector GHG target of 38 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) in 2030 and 30 $MMTCO_2e$ in 2035<br><br>Retail sales load coverage[134]<br><br>20 gigawatts (GW) of offshore wind by 2045<br><br>Meet increased demand for electrification without new fossil gas-fired resources. | SB 350 and SB 100: Reduce GHGs and improve air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br><br>In response to Governor Newsom's July 2022 letter, Board direction, and EJ Advisory Committee recommendation |
| New Residential and Commercial Buildings | All electric appliances beginning 2026 (residential) and 2029 (commercial), contributing to 6 million heat pumps installed statewide by 2030 | Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br><br>In response to Governor Newsom's July 2022 letter |

[134] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* reflects the agency authors' understanding that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Existing Residential Buildings | 80% of appliance sales are electric by 2030 and 100% of appliance sales are electric by 2035.<br><br>Appliances are replaced at end of life such that by 2030 there are 3 million all-electric and electric-ready homes—and by 2035, 7 million homes—as well as contributing to 6 million heat pumps installed statewide by 2030. | Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br><br>In response to Governor Newsom's July 2022 letter |
| Existing Commercial Buildings | 80% of appliance sales are electric by 2030, and 100% of appliance sales are electric by 2045.<br><br>Appliances are replaced at end of life, contributing to 6 million heat pumps installed statewide by 2030. | Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory<br><br>In response to Governor Newsom's July 2022 letter |
| Food Products | 7.5% of energy demand electrified directly and/or indirectly by 2030; 75% by 2045 | Reduce demand for fossil gas and GHGs, and improve air quality.<br><br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Construction Equipment | 25% of energy demand electrified by 2030 and 75% electrified by 2045 | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Chemicals and Allied Products; Pulp and Paper | Electrify 0% of boilers by 2030 and 100% of boilers by 2045.<br>Hydrogen for 25% of process heat by 2035 and 100% by 2045<br>Electrify 100% of other energy demand by 2045. | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Stone, Clay, Glass, and Cement | CCS on 40% of operations by 2035 and on all facilities by 2045<br>Process emissions reduced through alternative materials and CCS | SB 596: Reduce demand for fossil energy, process emissions, and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Other Industrial Manufacturing | 0% energy demand electrified by 2030 and 50% by 2045 | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Combined Heat and Power | Facilities retire by 2040. | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Agriculture Energy Use | 25% energy demand electrified by 2030 and 75% by 2045 | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions |
| Low Carbon Fuels for Transportation | Biomass supply is used to produce conventional and advanced biofuels, as well as hydrogen. | Reduce demand for petroleum fuel and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |
| Low Carbon Fuels for Buildings and Industry | In 2030s biomethane[135] blended in pipeline<br>Renewable hydrogen blended in fossil gas pipeline at 7% energy (~20% by volume), ramping up between 2030 and 2040<br>In 2030s, dedicated hydrogen pipelines constructed to serve certain industrial clusters | Reduce demand for fossil energy and GHGs, and improve air quality.<br>AB 197: direct emissions reductions for sources covered by the AB 32 Inventory |

[135] *Biomethane* is also known as renewable natural gas (RNG).

| Sector | Action | Statutes, Executive Orders, Other Direction, Outcome |
|---|---|---|
| Non-combustion Methane Emissions | Increase landfill and dairy digester methane capture.<br><br>Some alternative manure management deployed for smaller dairies<br><br>Moderate adoption of enteric strategies by 2030<br><br>Divert 75% of organic waste from landfills by 2025.<br><br>Oil and gas fugitive methane emissions reduced 50% by 2030 and further reductions as infrastructure components retire in line with reduced fossil gas demand | SB 1383: Reduce short-lived climate pollutants. |
| High GWP Potential Emissions | Low GWP refrigerants introduced as building electrification increases, mitigating HFC emissions | SB 1383: Reduce short-lived climate pollutants. |

## Natural and Working Lands

The Reference Scenario for NWL represents the amount of land management that occurred between 2001 and 2014, and projects the outcomes from maintaining the 2001–2014 levels of land management until 2045. The management and land use practices that occur within the Reference Scenario were derived from empirical data used by staff. For forests, shrublands/chaparral, and grasslands, the Reference Scenario constitutes approximately 250,000 acres of annual statewide treatments. For croplands, the Reference Scenario represents no healthy soil practices because during this period the healthy soil program did not yet exist. For land use change within all land types that consider land use change, historical rates of land conversion from 2001–2014 also were taken from empirical data and modeled into the future for the Reference Scenario.

Table 2-2 summarizes the Scoping Plan Scenario. The table also includes references to relevant statutes and Executive Orders where available.

**Table 2-2: Actions for the Scoping Plan Scenario: NWL sectors**

| Sector | Action | Statutes, Executive Orders, Outcome |
|---|---|---|
| Natural and Working Lands | Conserve 30% of the state's NWL and coastal waters by 2030.<br>Implement near- and long-term actions to accelerate natural removal of carbon and build climate resilience in our forests, wetlands, urban greenspaces, agricultural soils, and land conservation activities in ways that serve all communities—and in particular low-income, disadvantaged, and vulnerable communities. | EO N-82-20 and SB 27: CARB to include an NWL target in the Scoping Plan.<br>AB 1757: Establish targets for carbon sequestration and nature-based climate solutions.<br>SB 1386: NWL are an important strategy in meeting GHG reduction goals. |

| Sector | Action | Statutes, Executive Orders, Outcome |
| --- | --- | --- |
| Forests and Shrublands | At least 2.3 million acres[136] treated statewide annually in forests, shrublands/chaparral, and grasslands, comprised of regionally specific management strategies that include prescribed fire, thinning, harvesting, and other management actions. No land conversion of forests, shrublands/chaparral, or grasslands. | Restore health and resilience to overstocked forests and prevent carbon losses from severe wildfire, disease, and pests. Improve air quality and reduce health costs related to wildfire emissions. Improve water quantity and quality and improve rural economies. Provide forest biomass for resource utilization.<br><br>EO B-52-18: CARB to increase the opportunity for using prescribed fire.<br><br>AB 1504 (Skinner, Chapter 534, Statutes of 2010): CARB to recognize the role forests play in carbon sequestration and climate mitigation. |

[136] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

| Sector | Action | Statutes, Executive Orders, Outcome |
|---|---|---|
| Grasslands | At least 2.3 million acres[137] treated includes increased management of grasslands interspersed in forests to reduce fuels surrounding communities using management strategies appropriate for grasslands. No land conversion of forests, shrublands/chaparral, or grasslands. | Help to achieve climate targets, improve air quality, and reduce health costs. |
| Croplands | Implement climate smart practices for annual and perennial crops on ~80,000 acres annually. Land easements/ conservation on annual crops at ~5,500 acres annually. Increase organic agriculture to 20% of all cultivated acres by 2045 (~65,000 acres annually). | Reduce short-lived climate pollutants. Increase soil water holding capacity. Increase organic farming and reduce pesticide use.<br><br>SB 859: Recognizes the ability of healthy soils practices to reduce GHG emissions from agricultural lands.<br><br>Target increased in response to Governor Newsom's direction to prioritize sustainable land management. |

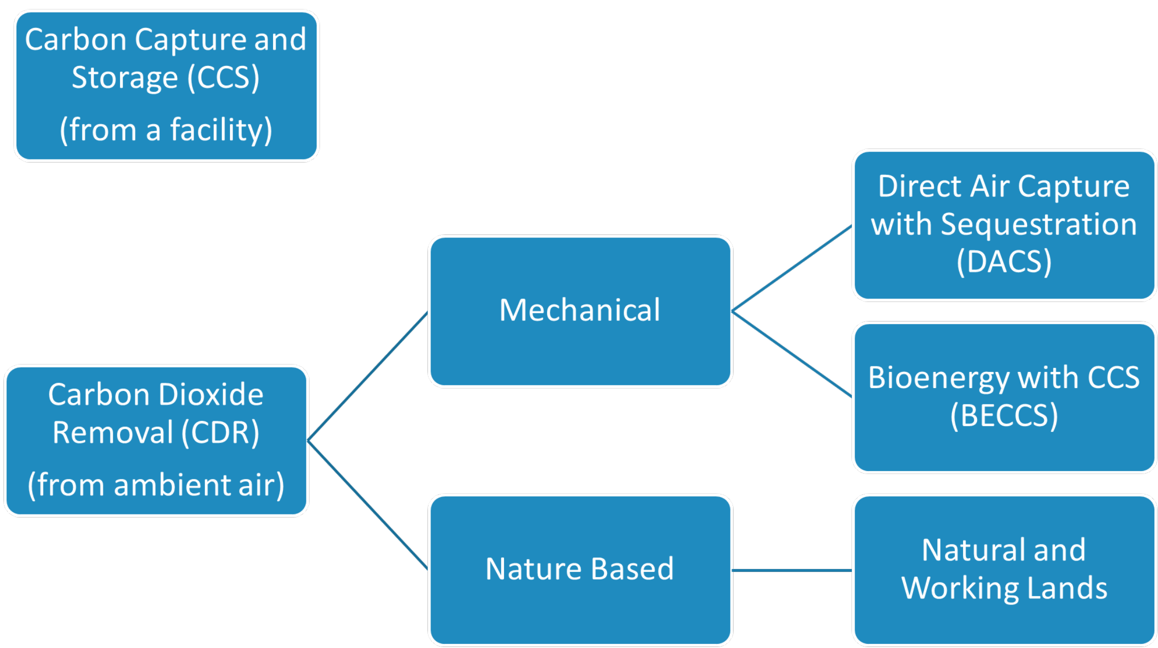
[137] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

| Sector | Action | Statutes, Executive Orders, Outcome |
|---|---|---|
| Developed Lands | Increase urban forestry investment by 200% above current levels and utilize tree watering that is 30% less sensitive to drought. Establish defensible space that accounts for property boundaries. | Increase urban tree canopy and shade cover. Reduce heat island effects and support water infrastructure. Reduce fire risk via defensible space.<br><br>AB 2251 (Calderon, Chapter 186, Statutes of 2022): Increase urban tree canopy 10% by 2035.<br><br>Target increased in response to AB 2251 and Governor Newsom's direction on $CO_2$ removal targets in his July 2022 letter. |
| Wetlands | Restore 60,000 acres of Delta wetlands. | Increase carbon sequestration and reduce short-lived climate pollutants. Helps to reverse land subsidence while improving flood protection and providing critical habitat. |
| Sparsely Vegetated Lands | Land conversion at 50% of the Reference Scenario land conversion rate. | Reduce the rate of land conversion to more GHG-intensive land uses. |

## Strategies for Carbon Removal and Sequestration

To achieve carbon neutrality, any remaining emissions must be compensated for using carbon removal and sequestration tools. The following discussion presents more detail on the options available to capture and sequester carbon. Carbon removal and sequestration will be an essential tool to achieve carbon neutrality, and the modeling clearly shows there is no path to carbon neutrality without carbon removal and sequestration. Governor Newsom also recognized the importance of $CO_2$ removal strategies and directed CARB to establish $CO_2$ removal and carbon capture targets of 20 $MMTCO_2$ and 100 $MMTCO_2$ by 2030 and 2045, respectively, as well as signing 2022 legislation on carbon removal and sequestration, including: AB 1279, SB 905, SB 1137, and AB 1757. Carbon removal and sequestration can take different forms. Figure 2-2 illustrates the types of carbon removal and sequestration included in this Scoping Plan. There are numerous other carbon removal options undergoing research, development, and pilot deployment. As these options mature and new approaches emerge, they can be considered in future Scoping Plan updates.

**Figure 2-2: Forms of carbon removal and sequestration considered in this Scoping Plan**




## The Role of Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) will be a necessary tool to reduce GHG emissions and mitigate climate change while minimizing leakage and minimizing emissions where no technological alternatives may exist. CCS is a process by which large amounts of $CO_2$ are captured, compressed, transported, and sequestered. CCS projects are paired with a source of emissions, as the CCS project captures $CO_2$ as it leaves a facility's smokestack. CCS projects are often paired with large GHG-emitting facilities such as energy, manufacturing, or fuel production facilities. The sequestration component of CCS includes $CO_2$ injection into geologic formations (such as depleted oil and gas reservoirs and saline formations), as well as use in industrial materials (e.g., concrete). CCS is distinct from biological sequestration, which is typically accomplished through NWL management and conservation practices that enhance the storage of carbon or reduce $CO_2$ emissions with nature-based approaches. CCS is also distinct from mechanical $CO_2$ removal technologies, where $CO_2$ is removed directly from the atmosphere using mechanical and/or chemical processes.

CARB adopted a CCS Protocol in 2018 as part of amendments to the Low Carbon Fuel Standard.[138] At this time, no CCS projects have been implemented or have generated any credits under that protocol. However, CCS projects have been implemented elsewhere since the 1970s, largely on coal-fired power plants, with over two dozen projects operational around the world. Over 100 are at the stages of advanced or early development and are expanding beyond coal-fired plants to fossil gas, fuel production, and electricity generation facilities.[139] CCS projects are in development for addressing emissions from fuel, gas, energy production, and chemical production. As of November 2019, more than half of global large-scale CCS facilities (representing approximately 22 $MMTCO_2$/yr in capacity[140]) were in the U.S., mostly as a result of sustained governmental support for these technologies.[141] This support includes the federal 45Q tax credit for CCS[142,143] and research and deployment grants from federal agencies.[144,145] California's deep sedimentary rock formations in the Central Valley represent world-class

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[138] CARB. 2022. Carbon Capture & Sequestration. https://ww2.arb.ca.gov/our-work/programs/carbon-capture-sequestration.

[139] Global CCS Institute. 2021. *Global Status of CCS 2021.* https://www.globalccsinstitute.com/wp-content/uploads/2021/11/Global-Status-of-CCS-2021-Global-CCS-Institute-1121.pdf.

[140] IHS Markit. August 2021. Carbon Removal Potential: An Overview. https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf.

[141] Beck, Lee. 2019. *Carbon capture and storage in the USA: The role of US innovation leadership in climate-technology commercialization.* https://academic.oup.com/ce/article/4/1/2/5686277.

[142] Congressional Research Service. 2021. Carbon Storage Requirements in the 45Q Tax Credit. IF11639. https://crsreports.congress.gov/product/pdf/IF/IF11639.

[143] The Inflation Reduction Act of August 2022 expands and enhances the 45 Q tax credit for CCS. Pub.L. No. 117-169 (August 16, 2022).

[144] U.S. Department of Energy. 2020. U.S. Department of Energy Announces $131 Million for CCUS Technologies. https://www.energy.gov/articles/us-department-energy-announces-131-million-ccus-technologies.

[145] U.S. Department of Energy. 2021. Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants. https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

$CO_2$ storage sites that would meet the highest standards, with storage capacities of at least 17 billion tons of $CO_2$.[146,147]

In this Scoping Plan, CCS is included to address emissions from limited sectors, including electricity generation, cement production facilities, and refineries, to ensure anthropogenic emissions are reduced by at least 85 percent below 1990 levels in 2045, as directed in AB 1279. While the modeling outputs show CCS not being applied to the electricity sector until 2045, CCS could be implemented earlier on the electricity sector with a similar ramp up over time as that for refineries and cement plants. An earlier application of CCS in the electricity sector would yield additional reductions in years prior to 2045. In addition, CCS can support hydrogen production until such time as there is sufficient renewable power for electrolysis and an abundant water source.

Cement plants have emissions associated with combustion and process-related activities. Combustion emissions account for approximately 40 percent of the total emissions at cement plants. The remaining emissions are related to process-related activities. Due to the high heat content needed to produce cement, there is currently no technically feasible alternative to combustion. SB 596 calls for a 40 percent reduction in GHG intensity in cement emissions from 2019 levels by 2035, and then net zero emissions by 2045. To meet in-state demand, the state relies on cement both produced in state and imported. There are seven cement plants operating in California.[148] To minimize emissions leakage and address emissions from cement plants, the Scoping Plan Scenario includes CCS for cement plants. Additional reductions will need to be pursued and considered as part of implementation of SB 596, which calls for CARB to develop a comprehensive strategy by July 1, 2023, for the state's cement sector to achieve net-zero emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. This effort began in the summer of 2022 and included sector specific workshops.

Even with implementation of EO N-79-20, and despite all of the ambitious efforts in the Scoping Plan Scenario, there will remain some demand for petroleum fuels for legacy vehicles on road applications, and in aviation, rail, and marine applications. Petroleum refineries will need to implement technology to decarbonize their operations and reduce their emissions. This Scoping Plan also assumes CCS at petroleum refineries as one of those potential strategies. Currently, there are seventeen petroleum refineries operating

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[146] For comparison purposes, California's emitted 418.2 million metric tons of $CO_2e$ in 2019.
[147] Lawrence Livermore National Laboratory. 2020. *Getting to Neutral: Options for Negative Carbon Emissions in California.* Revision 1. https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[148] CARB. Mandatory GHG Reporting – Reported Emissions. https://ww2.arb.ca.gov/mrr-data

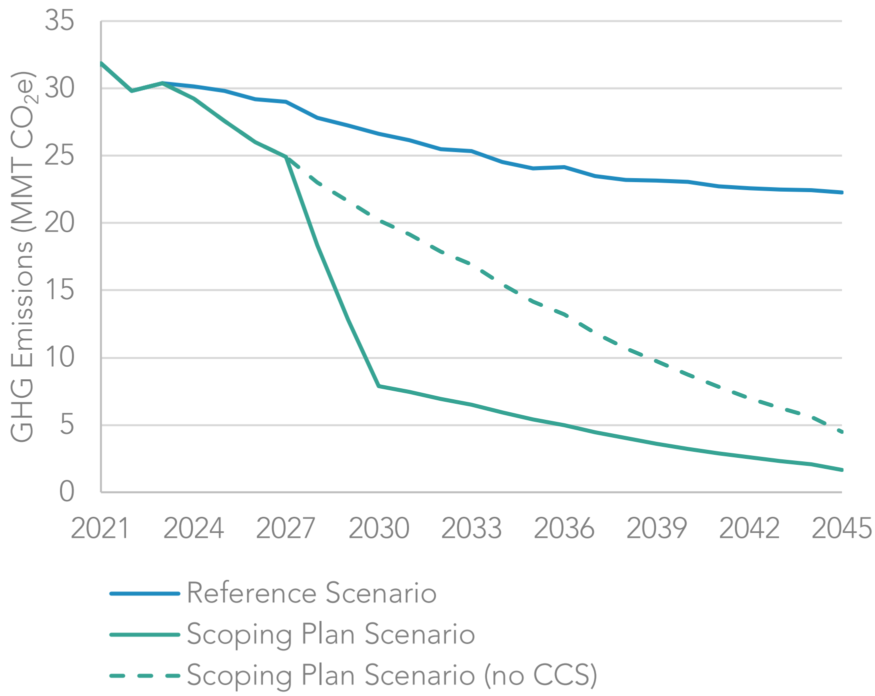
in the state.[149] On the supply side, the modeling assumes all in-state demand is met through some very limited refining activities in California. Figure 2-3 shows the emissions from the refining sector with and without CCS. If CCS is not deployed, the emissions would be directly emitted into the atmosphere, and $CO_2$ removal by NWL or direct air capture would need to increase to compensate for the sector's emissions.

Refineries can have a variety of point sources that emit $CO_2$—such as steam methane reformers for producing hydrogen, combined heat and power units, and catalytic crackers—that are best suited for CCS. Each configuration of a refinery can be unique to its footprint, onsite operations, and the types of crude oils processed. There are newer technologies with smaller footprints[150] that can be deployed in modular configurations to capture $CO_2$ in space-constrained and multiple-point-source facilities such as refineries. CCS can provide a path to reducing GHG emissions from these facilities to meet petroleum demand while avoiding leakage and until such time as some refineries can be transitioned to produce clean energy to support the transition away from fossil fuels.

While the Scoping Plan modeled deployment of CCS on refineries and identifies significant emissions reductions that can be achieved, the refineries in California are large and complex. The actual deployment of CCS at these facilities as modeled in the Scoping Plan is uncertain. It will be important to closely monitor the evolution of CCS deployment in the refinery sector and, in the next Scoping Plan update, to evaluate the progress toward use in this sector to determine whether the projected reductions will be achieved.

[149] CARB. Mandatory GHG Reporting. https://ww2.arb.ca.gov/mrr-data.
[150] Carbon Clean. Modular Carbon Capture Systems for Industry. https://www.carbonclean.com/modular-systems?hsLang=en.

**Figure 2-3: Petroleum refining emissions with and without carbon capture and sequestration**




This Scoping Plan also calls for accelerating the transition from combustion of fossil fuels to hydrogen. Hydrogen can be produced through electrolysis with renewable electricity or through steam methane reformation of biomethane. There is a high degree of uncertainty around the availability of solar to support both electrification of existing sectors and the production of hydrogen through electrolysis. Producing hydrogen required under the Scoping Plan Scenario with electrolysis would require about 10 gigawatts (GW)[151] of additional solar capacity. If steam methane reformation is paired with CCS, the hydrogen produced could potentially be low carbon. Additionally, the biomethane used to generate hydrogen could be sourced from gasification of forest or agricultural waste resulting from forest management and other NWL management practices, which could also lead to net negative carbon outcomes. Steam methane reformation paired with CCS can thus ensure a rapid transition to hydrogen and increase hydrogen availability until such time as

[151] The Draft Scoping Plan included an estimate for solar capacity (40 GW) to support only electrolysis to produce all hydrogen in the Proposed Scenario. The Scoping Plan now includes steam methane reformation of biomethane and biomass gasification with CCS to produce hydrogen, along with electrolysis from off-grid solar. See Appendix H (AB 32 GHG Inventory Sector Modeling) for additional details.

electrolysis with renewables can meet the ongoing need, assuming there is also sufficient water supply. Additional background and next steps for CCS can be found in Chapter 4.

The EJ Advisory Committee has raised multiple concerns related to the inclusion of CCS and mechanical CDR in the Scoping Plan. Concerns range from potential negative health and air quality impacts in communities from operation of facilities utilizing CCS that continue to emit other emissions, to safety concerns related to potential leaks, to the viability of the current technology. Additionally, the EJ Advisory Committee has policy concerns about the strategy and wants to ensure that engineered carbon removal is not used as a substitute for strategies to achieve emissions reductions onsite and that it does not result in delays in phasing out fossil fuel use. Given these and other concerns and the importance of building public awareness, CARB recognizes the need for a multi-stakeholder process including other state, federal, and local agencies; tribes; independent experts; and community residents to further understand and address community concerns related to CCS. CARB hosted a CCS Symposium with U.S. EPA Region 9 and the Stanford Doerr School of Sustainability to discuss some of these critical issues with community members and other participants. As CARB begins the process of implementing SB 905 in 2023, that will provide an opportunity for further engagement.

In the context of CCS deployment, the Council of Environmental Quality (CEQ) also highlighted the need to further assess and quantify potential impacts on local criteria air pollutants and other emissions resulting from carbon capture retrofits at industrial facilities in response to concerns regarding potential cumulative emissions from single and/or multiple sources.[152] An October 2020 Stanford report[153] discussed how the potential post-combustion capture for $CO_2$ could also reduce emissions of criteria air pollutant emissions from certain facilities. Exploring these potential outcomes will be important to ensure deployment of CCS does not exacerbate air pollution impacts in communities and maximizes any air pollution benefits. The need for these types of evaluations is also included in SB 905.

## The Role of Natural and Working Lands Emissions and Sequestration

California's NWL assessments highlight the importance of increasing the pace and scale of NWL actions to ensure that our ecosystems are better equipped to withstand future climate change so they continue to provide the benefits that nature and society depend

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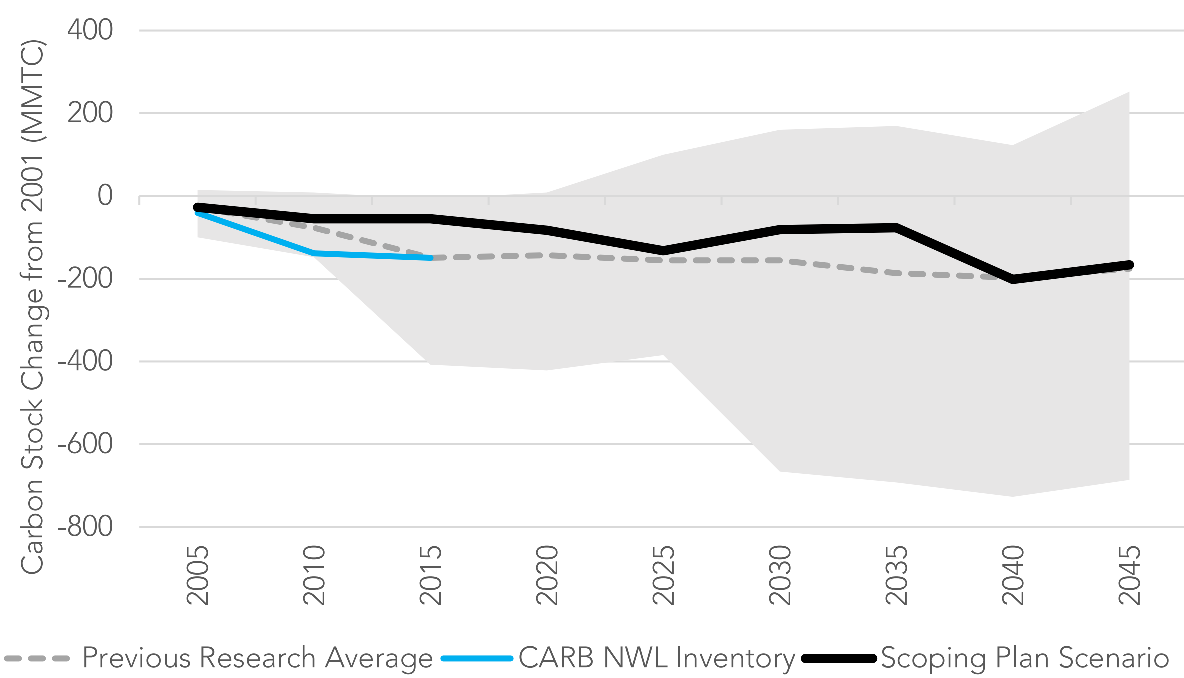
[152] Carbon Capture, Utilization, and Sequestration Guidance. 87 Fed. Reg. 8808 (Feb. 16, 2022), [2022-03205.pdf (govinfo.gov)](2022-03205.pdf (govinfo.gov)).

[153] Stanford Center for Carbon Storage. 2020. *An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions.* October. https://sccs.stanford.edu/ccs-in-ca/full-report-form?msclkid=6f9177f6c57811ecbebc473e75203b21.

upon for survival. As climate change increases the likelihood of extreme wildfires, drought, heat, and other impacts, carbon stocks in California's NWL will face increased risks and impacts. We know from previous climate change and Scoping Plan work[154] that lands can be a net source of GHG emissions or a net sink, and that the magnitude of carbon stock changes and GHG emissions and sequestration from NWL are dependent on the effects of climate change and land management. The expanded modeling conducted for this Scoping Plan shows that NWL are projected to be a net source of emissions through 2045 and indicates a probable decrease of carbon stocks into the future. This projection is further corroborated by previous, independent research that has reached the same conclusion, showing a range of varying levels of carbon stock loss. Figure 2-4 shows the modeling results of the Scoping Plan Scenario overlaid with the NWL inventory and findings from independent research.

**Figure 2-4: Comparison of the Scoping Plan Scenario (NWL) with existing research**




The modeling indicates that immediate and aggressive climate action can reduce the environmental impacts that would occur in the absence of this action. The results of the modeling demonstrate that regular NWL management over the next two decades can

[154] CARB. 2019. January 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan*. https://ww2.arb.ca.gov/sites/default/files/2020-10/draft-nwl-ip-040419.pdf.

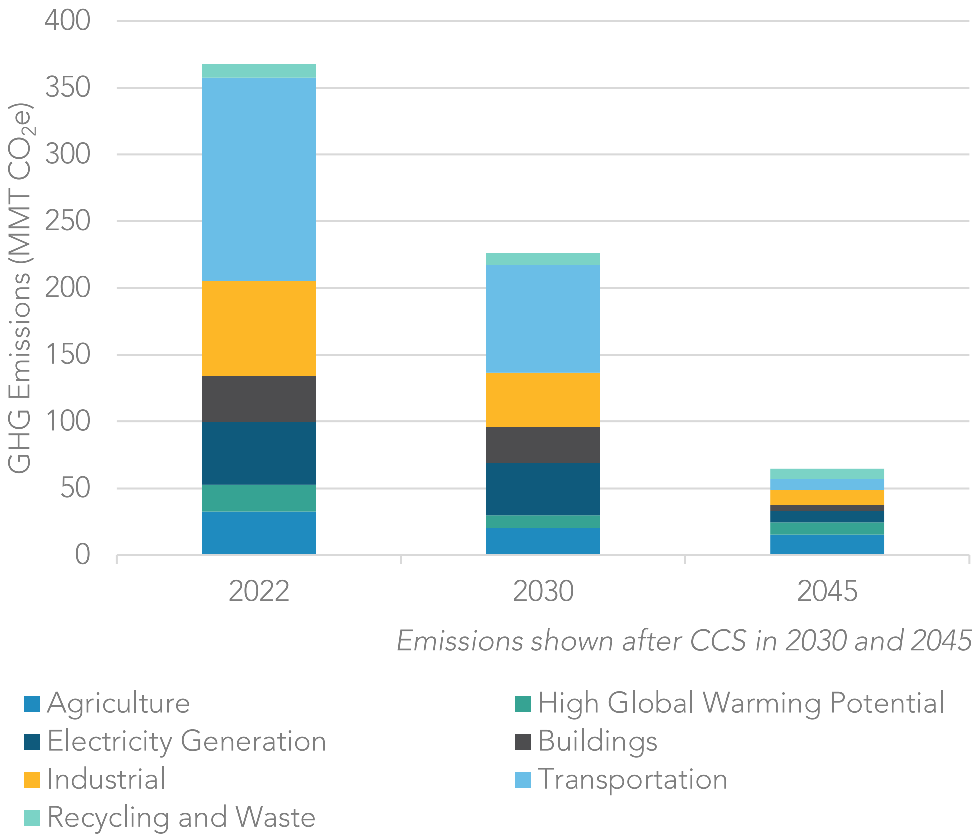
increase carbon stocks from the Reference Scenario trajectory, reduce GHG emissions from lands, and improve ecosystem and public health. This effort is the most comprehensive scientific effort taken by any government to include NWL within its overall climate strategy. Even so, we know that uncertainty exists about future climate and economic forces and the impacts they may have on our ecosystems, so it is important that the state take decisive and aggressive action to improve and diversify ecosystem structures and management.

The effects of climate change, including increased drought, wildfire, and extreme heat, play a significant role in determining the future of California's carbon stocks. And while management actions will help to reduce the impact that climate change will have on California, it is clear from the analysis that NWL sinks and sources are highly variable from year to year, and short time frames do not adequately demonstrate the impact that climate and management are having on ecosystems. For the purposes of climate planning, therefore, it is best to focus on carbon stock changes over longer periods rather than focusing on sequestration or emissions on shorter time frames. The Scoping Plan Scenario is estimated to result in additional NWL emissions of 7 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) annually from 2025–2045. The Reference Scenario is estimated to result in annual emissions of 9 $MMTCO_2e$ over the same time period, and so the Scoping Plan Scenario slows the rate of emissions and provides an approximate 2 $MMTCO_2e$ in additional annual sequestration relative to the Reference Scenario. Because NWL are projected to be a net emissions source, the annual NWL emissions of approximately 7 $MMTCO_2e$ from the Scoping Plan Scenario will need to be compensated by additional $CO_2$ removal approaches to ensure California can achieve carbon neutrality by 2045.

## The Role for Carbon Dioxide Removal (Direct Air Capture)

Even if anthropogenic emissions are reduced to at least 85 percent below 1990 levels by 2045 as called for by AB 1279, there will still be residual emissions in the AB 32 GHG Inventory sectors in 2045 that must be addressed in order to achieve the California's carbon neutrality target. Figure 2-5 includes the emissions by sector for the AB 32 GHG Inventory Sectors in 2022, 2030, and 2045 for the Scoping Plan Scenario.

**Figure 2-5: Residual emissions in 2022, 2030, and 2045 for the Scoping Plan Scenario**[155]




To achieve carbon neutrality, mechanical CDR will therefore need to be deployed. Because NWL management is not estimated to be a significant carbon removal path in the near term, additional CDR options will be needed. *Mechanical CDR* refers to a range of technologies that capture and concentrate ambient $CO_2$. Direct air capture (DAC) is one available option that is under development today and could be widely deployed. Note that, unlike CCS, DAC technologies are not designed to be attached to a specific source or smokestack. These technologies include chemical scrubbing processes that capture $CO_2$ through absorption or adsorption separation processes. Another carbon removal

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[155] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, $SF_6$ emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily hydrofluorocarbons (HFCs), are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

option that involves rapid mineralization of $CO_2$ at the Earth's surface is called *mineral carbonation.*[156] As is the case with CCS, mechanical CDR technologies will need governmental or other incentive support to overcome technology and market barriers. In the United States, the U.S. Department of Energy announced financing specifically for DAC in March 2020[157] and March 2021.[158] Additionally, almost $9 billion in CCS support was included in the $ 1 trillion Infrastructure Investment and Jobs Act of 2021.[159] This includes funding to establish four DAC hubs. The Inflation Reduction Act of 2022[160] increases the value of the 45Q tax credit to USD 85 per metric ton of $CO_2$ captured and stored in geologic formations from some industrial applications and USD 180 per metric ton for DAC with storage in geologic formations. In 2021, there were approximately 19 DAC facilities globally.[161]

Ultimately, the role for mechanical CDR will depend on the success of reducing emissions directly at the source in the AB 32 GHG Inventory sectors and the ability of the NWL to sequester carbon. However, mechanical CDR also provides an opportunity to not just achieve carbon neutrality, but also remove legacy GHG emissions from the atmosphere. As such, increased deployment of DAC can help achieve net negative emissions. This would further help avoid the most damaging impacts of climate change. While the federal incentives for DAC provide some support for this technology, the only California program that recognizes this technology is the LCFS program. Permitting must also happen across different levels of government and across multiple state agencies. Energy availability must also be addressed if DAC is to be implemented in remote areas. Additional information and next steps on DAC can be found in Chapter 4.

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[156] The National Academies Press. 2018. Direct Air Capture and Mineral Carbonation Approaches for Carbon Dioxide Removal and Reliable Sequestration: Proceedings of a Workshop–in Brief. *https://nap.nationalacademies.org/catalog/25132/direct-air-capture-and-mineral-carbonation-approaches-for-carbon-dioxide-removal-and-reliable-sequestration#:~:text=National%20Academies%20of%20Sciences%2C%20Engineering%2C%20and%20Medicine%3B%20Division,concentrate%20carbon%20dioxide%20%28CO%202%29%20from%20ambient%20air*.
[157] U.S. Department of Energy. 2020. Department of Energy to Provide $22 Million for Research on Capturing Carbon Dioxide from Air. *https://www.energy.gov/articles/department-energy-provide-22-million-research-capturing-carbon-dioxide-air*.
[158] U.S. Department of Energy. 2021. DOE Invests $24 Million to Advance Transformational Air Pollution Capture. *https://www.energy.gov/articles/doe-invests-24-million-advance-transformational-air-pollution-capture*.
[159] Pub.L. No. 117-58 (November 15, 2021). *https://www.congress.gov/bill/117th-congress/house-bill/3684/text*.
[160] Pub.L. No. 117-169 (August 16, 2022). *https://www.congress.gov/bill/117th-congress/house-bill/5376/text*.
[161] International Energy Agency (IEA). 2022. Direct Air Capture – Analysis. *https://www.iea.org/reports/direct-air-capture*.

## Carbon Dioxide Removal and Capture Targets for 2030 and 2045

Recognizing the importance of $CO_2$ removal, Governor Newsom and the Legislature identified the need for targets to send policy and regulatory signals to pilot, deploy, and scale action for those efforts. Governor Newsom requested that CARB set a $CO_2$ removal and capture target of 20 MMT for 2030 and 100 MMT for 2045, first prioritizing sequestration in NWL. And while this Scoping Plan prioritizes and recommends significant increased climate-smart action on all NWL to support carbon neutrality and healthy and resilient lands, the modeling indicates that, across all NWL, lands will be a net source of emissions when accounting for both carbon sequestration and GHG ($CO_2$, $CH_4$, and $N_2O$) emissions from lands.

Some landscapes, however, are projected to have a net increase in carbon stocks under the Scoping Plan Scenario between 2025 and 2045 relative to the reference case, indicating that NWL actions can help California achieve Governor Newsom's $CO_2$ removal targets. Carbon stocks in urban forests and grasslands are projected to increase relative to historical levels from implementation of the 2022 Scoping Plan. To support the governor's $CO_2$ removal targets, CARB estimates that lands would contribute an average of 1.5 MMT of $CO_2$ removals each year between 2025 and 2045. Any carbon sequestration contributions from lands need to reflect both long-term storage and an overall net increase in carbon stocks over time to ensure these NWL actions are contributing toward California's achievement and maintenance of carbon neutrality over time.

CARB will work to update and revise these estimates as part of implementation of AB 1757, which was signed by the governor in September 2022 and requires that CARB and the California Natural Resources Agency (CNRA) work with an expert advisory committee to determine an ambitious range of carbon sequestration targets by January 1, 2024, for the years 2030, 2038, and 2045.

For the AB 32 GHG Inventory sectors, the Scoping Plan Scenario modeling indicates that the scenario would meet or exceed the 2030 SB 32 target through GHG reduction policies without the need for CDR. CDR will, however, be necessary to increase ambition for an accelerated 2030 target and in increasing amounts over the following decades to achieve carbon neutrality by 2045.[162] Given the likelihood of NWL to be a net source of emissions, and the need for CDR to compensate for residual emissions to achieve carbon neutrality

[162] The modeled scenarios assume that residual emissions will be compensated using DAC technologies by including the direct cost in terms of dollars per ton $CO_2$ removed. The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero carbon options consistent with the carbon neutrality targets in this Scoping Plan.

by 2045, California will need increasing deployment of mechanical CDR over the coming decades. In the immediate future, scaling nature-based CDR approaches also can help to provide some $CO_2$ removal quickly while mechanical CDR is scaled up between now and 2045. Table 2-3 provides estimates of $CO_2$ removal and capture needed in 2030[163] and 2045.

[163] As identified in Chapter 1, SB 27 (Skinner, Chapter 237, Statues of 2021) directed CARB to "establish carbon dioxide removal targets for 2030 and beyond" as part of this Scoping Plan. CARB is establishing these targets to satisfy both the requirements of SB 27 and the directive from Governor Newsom to establish $CO_2$ removal targets for 2030 and 2045.

**Table 2-3: GHG emissions and removals needed to achieve carbon neutrality and meet the 20 $MMTCO_2$ removal and capture target in 2030 and the 100 $MMTCO_2$ removal and capture target in 2045.**[164]

| | 2030 ($MMTCO_2e$) | 2045 ($MMTCO_2e$) |
|---|---|---|
| GHG Emissions | 233 | 72 |
| AB 32 GHG Inventory Sector Emissions | 226 | 65 |
| Net NWL GHG Emissions Across All Landscapes (annual average from 2025–2045) | 7 | 7 |
| Carbon Capture and Sequestration (CCS): Avoided GHG Emissions from Industry and Electric Sectors | (13) | (25) |
| Carbon Dioxide Removal (CDR) including natural and working lands carbon sequestration,[165] Direct Air Capture, and Bioenergy with CCS (BECCS). | (7) | (75) |
| Net Emissions (GHG Emissions + CDR) | 226 | (3) |

In 2030, the $CO_2$ removal and capture target is 20 MMT, but because the SB 32 target only encompasses the AB 32 GHG Inventory sectors, only CCS that reduces GHG emissions on AB 32 sources count toward achieving more ambitious GHG emission reductions in 2030. In 2045, the $CO_2$ removal and capture must compensate for any residual emissions from the AB 32 Inventory sectors and NWL emissions to support achieving carbon neutrality while also totaling at least 100 MMT. It is important to note that NWL, particularly forests, need a natural wildfire cycle to remain healthy. While the modeling projected wildfires, and implementing the Scoping Plan will result in a reduction in future wildfire emissions, getting to zero wildfires in the sector is not the goal, nor the

[164] Modeled estimates from the Scoping Plan Scenario indicate the relative quantity of emissions and removals to achieve carbon neutrality and meet carbon removal and capture targets. These estimates are not intended to imply precision, as the required policies are yet to be implemented and all models have some uncertainty in their forecasts.
[165] For the purposes of quantifying how to achieve the governor's 20 MMT and 100 MMT $CO_2$ removal and capture target, CARB included 1.5 $MMTCO_2e$ sequestration from NWL, which is the sequestration from urban forests. This is included as $CO_2$ removal because it is this sequestration that CARB can consider as having some permanence. Permanence is necessary for incorporating NWL into carbon neutrality. The net NWL emissions of 7 $MMTCO_2e$, identified in the second row of Table 2-3, includes *all* emissions and sinks from all NWL landscapes, which is inclusive of the 1.5 $MMTCO_2e$ sequestration. CARB will develop an accounting framework to accommodate NWL carbon stocks.

right approach to a sustainable forestry sector. In contrast in 2045, the reductions from programs and policies are estimated to reduce emissions by 169 $MMTCO_2e$ from business as usual.

The 2030 target for engineered CDR also provides a near term milestone for California and can serve as an important marker for progress in deploying CDR to support California's carbon neutrality goal. Preliminary estimates indicate that, globally, capacity from already announced projects will range from about 2 million metric tons per year ($MMTCO_2/y$) to 8 $MMTCO_2/y$ from bioenergy paired with CCS, and from about 2,000 metric tons per year ($MTCO_2/y$) to 1 $MMTCO_2/y$ from DACs by 2027,[166] which indicates that California's 2030 target is an ambitious, but achievable, goal.

# Scenario Uncertainty

## Greenhouse Gas Emissions Modeling

Several types of uncertainty are important to understand in both forecasting future emissions and estimating the benefits of emission reduction actions. In developing this Scoping Plan we forecasted a reference scenario and estimated the GHG emissions outcome of the AB 32 GHG Inventory sectors using the PATHWAYS[167] model. Inherent in the reference scenario modeling is the expectation that many of the existing programs will continue in their current form, and that the expected drivers for GHG emissions, such as energy demand, population growth, and economic growth, will match our current projections.

However, there is also the expectation that each of the policies included and implemented to achieve the 2030 target in the 2017 Scoping Plan will deliver their exact outcomes. It is unlikely the future will precisely match our projections, and this will lead to uncertainty in the forecast. For example, we never could have foreseen and forecasted economic and emissions impacts related to the extended disruptions from the COVID-19 pandemic. Thus, the single "reference" or "forecast" line should be understood to represent one possible future in a range of possible predictions. For this Scoping Plan, PATHWAYS utilized inputs that reflect technically feasible levels of deployment or adoption of low- or zero-carbon fuels and technologies. Each of the input assumptions provided to PATHWAYS has some uncertainty, which also contributes to uncertainty in the resulting reference scenario.

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[166] IHS Markit. August 2021. Carbon Removal Potential. https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf.
[167] See Appendix H (AB 32 GHG Inventory Sector Modeling).

Similarly, for the NWL modeling, CARB used a mix of individual modeling tools[168] to estimate the carbon and other ecological, public health, and economic outcomes. The Reference scenario assumes that the level of land management actions that occurred between 2001 and 2014 for forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands continues into the future. Alternative scenarios assessed the effect of increasing levels of management actions from the reference scenario beginning in 2025. There is a great deal of uncertainty about exactly how lands are currently managed, and a larger uncertainty about how they may be managed in the future. For NWL, it is unlikely that the future will precisely match the carbon stock outcomes CARB has projected, particularly given the uncertainties around current and future land management and the effects climate change will have on our lands. For any modeling exercise these uncertainties exist; however, this modeling effort brings together the best available science, data, and models to quantify the impact our actions may have on the landscape under an unknown future.

## Implementation

As this Scoping Plan is designed to chart a path to achieving carbon neutrality, additional work will be required to fully design and implement any policies and actions identified in this plan. During the subsequent development of policies, the Legislature, CARB, and other state agencies will learn more about the technologies and their costs, as well as how each industry works, as a more comprehensive evaluation is conducted in coordination with stakeholders, including community engagement. Significant areas of uncertainty include permitting wait times[169] and local ordinances that might limit or slow the build-out of utility scale renewables.[170,171] In another example, times to reach commercial operations for solar projects after securing an interconnection agreement also have increased in recent years, to 3.5 to 5.5 years.[172]

The level of natural and working lands climate action identified in this Scoping Plan is ambitious. Achieving the level of action needed to result in the quantified carbon,

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[168] See Appendix I (Natural and Working Lands Technical Support Document).
[169] CEC. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100#anchor_report.
[170] Roth, Sammy. 2019. "California's San Bernardino County slams the brakes on big solar projects." *Los Angeles Times.* https://www.latimes.com/business/la-fi-san-bernardino-solar-renewable-energy-20190228-story.html?fbclid=IwAR2qHGq3bahHme6SFErLsnyFi9UPIfBHIhvnOh3dU3OM7kUTMcEqYfN3pQA.
[171] Chediak, Mark. 2021. "California NIMBYs Threaten Biden's Clean Energy Goals." *BNN Bloomberg.* https://www.bnnbloomberg.ca/california-nimbys-threaten-biden-s-clean-energy-goals-1.1634351?msclkid=668c9ae9c11311ec92e34035ea157ad4.
[172] Rand, Joseph, et al. 2022. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021. Power Point Presentation. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf.

emissions, health, and economic outcomes within this Scoping Plan requires coordination, investment, and partnerships across all levels of government and sectors of the economy. It is possible that not all of the actions at the identified level will begin in 2025. This uncertainty will result in diminished levels of beneficial outcomes quantified in the Scoping Plan Scenario. The levels of NWL action identified in this Scoping Plan represent CARB's assessment of the pace and scale of action needed to achieve the carbon stock targets and $CO_2$ removal targets identified in this Scoping Plan.

The Scoping Plan Scenario identifies that 2.3 million acres of forests, shrubland, and grassland management annually would achieve substantial levels of fire emissions reductions and the concomitant health and economics benefits. Currently, 1 million acres of forest treatment annually is the joint federal and state government goal (500,000 acres each). This target of one million acres annually by 2025 is for the purposes of increasing forest health and wildfire resilience in the near term, whereas the 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045. By identifying 2.3 million acres of climate action annually in forests, shrublands, and grasslands, this Scoping Plan emphasizes the importance of that 1 million acre annual goal as a milestone on the way to even more action and improved fire and air quality outcomes. The modeling indicates that substantial improvements to statewide fire emissions will occur at levels of action greater than 1 million acres per year. If these levels of action do not occur starting in 2025, the Scoping Plan has quantified climate benefits that will still occur, but to a lesser extent. In terms of fire emissions, compared to the Reference Scenario, 2.3 million acres of forest, shrubland and grassland management will result in a 10% reduction in wildfire emissions. At 1 million acres per year, this decreases to a 2.5% reduction. If 1 million acres per year is also not accomplished, then the emissions and health benefits are even lower.

Climate action in other NWL sectors also generates many co-benefits. Climate action identified in this Scoping Plan is aimed at not only fighting climate change but also improving air quality and public health. The climate action identified in the agricultural sector, for example, should result in decreased pesticide and synthetic fertilizer use. This decrease of synthetic chemical use in agriculture across California also should result in improved public health, especially for communities that work and live in and around agricultural lands. However, as with the forestry sector, the benefits of climate action in agricultural lands and in any other land are dependent on how much implementation takes place. Ramping up increased healthy soils practices and increasing organic agriculture in California will require continued and sustained implementation by private industry and public agencies. For example, achieving the carbon stock outcomes for the annual crops called for in this Scoping Plan would require deployment and maintenance of healthy soils practices on 80,000 additional acres of croplands in California every year between 2025 and 2045. For context, CDFA's Healthy Soils Program, which is an incentive program supporting healthy soils practices, took almost four years of sustained funding to achieve approximately 50,000 acres total under healthy soils practices.[173]

Given the uncertainty around the modeling assumptions, and performance uncertainty as specific policies are fully designed and implemented, estimates associated with the Scoping Plan Scenario are certain to be different than what is ultimately implemented. One way to mitigate for this is to develop policies that can adapt and increase certainty in GHG emissions reductions. Periodic reviews of progress toward achieving the 2030 target and longer term deeper decarbonization, as well as performance of specific policies, also provide opportunities for the state to consider any changes to ensure we remain on course to achieve the 2030 target and carbon neutrality. The need for this periodic review process was anticipated in AB 32, as it calls for updates to the Scoping Plan at least once every five years. For this Scoping Plan, the metrics provided on the rate of deployment of clean fuels and technologies, along with the annual AB 32 GHG Inventory, provide additional information that can be used to assess progress on sectors and aggregate emissions. This is also true of CARB's NWL carbon inventory. An uncertainty analysis for achieving an accelerated 2030 target is provided toward the end of this chapter.

## Targeted Evaluations for the Scoping Plan: Oil and Gas Extraction and Refining

To achieve California's air quality and climate goals, we must end our dependence on petroleum. This will not happen overnight. There are about 28 million combustion engine heavy- and light-duty trucks and passenger vehicles in California, and these are almost always replaced at their end of life. The ZEV Executive Order (EO N-79-20) calls for 100 percent new ZEV car sales beginning in 2035 and a 100 percent ZEV medium- and heavy-duty fleet sales by 2045 where feasible. The result is an ongoing, albeit shrinking, pool of vehicles that will continue to require petroleum fuels. To avoid leakage, as called for in AB 32, and to meet that remaining demand for petroleum fuel, a complete phaseout of oil and gas extraction and refining is not possible by 2045. This Scoping Plan assumes a phasedown in both oil and gas extraction as well as petroleum refining in line with the reduction in demand for in-state on-road petroleum fuel demand. Since the transportation sector is the largest source of GHG emissions and harmful local air pollution, we must continue to research and invest in efforts to deploy zero emissions technologies and clean fuels, and to reduce VMT. An assessment of ongoing progress and efforts to reduce

[173] California Department of Food and Agriculture. 2021. *Incentives Program 2017–2020 Summary by the Numbers.* https://www.cdfa.ca.gov/oefi/healthysoils/docs/HSP_Incentives_program_level_data_funded_projects.pdf.

demand for petroleum fuels and of opportunities to phase down oil and gas extraction and refining will be included in the next Scoping Plan update.

In addition to supplying in-state demand, California is a net exporter of gasoline, diesel, and jet fuel. California pipelines supply the Nevada and Arizona regions[174] with approximately 87 million barrels gasoline equivalent of refined products annually.[175] California pipelines deliver approximately 85% of Nevada's and 40% of Arizona's refined product. Most finished fuels flowing from California to Nevada and Arizona are currently produced by California refineries. To manage the phasedown of oil and gas extraction and petroleum refining in California, exports of finished fuels must be considered and factored into that process, in addition to the declining in-state demand. The authorities and considerations related to supply and demand of petroleum fuels span federal, state, and local agencies. If supply of fossil fuels is to decline along with demand, a multi-agency discussion is needed to systematically evaluate and plan for the transition to ensure that it is equitable.

This inter-agency work should also consider related topics, such as the following:

- Direct and indirect job and economic impacts
- Demand for other liquid fuel types such as renewable fuels, and expected volumes
- Legal considerations
- Public health benefits
- Demand and supply strategies for petroleum fuels, including how to avoid short term supply constraints that may impact low-income consumers

Some of these topics were also discussed as part of two studies[176] supported by the California Environmental Protection Agency, which can serve as a starting point for a working group to analyze these questions and develop policy recommendations.

## Oil and Gas Extraction

On April 23, 2021,[177] Governor Newsom directed CARB to evaluate the phaseout of oil and gas extraction no later than 2045 as part of this Scoping Plan. As noted above, this Scoping Plan still has some California demand for finished fossil fuels (gasoline, diesel,

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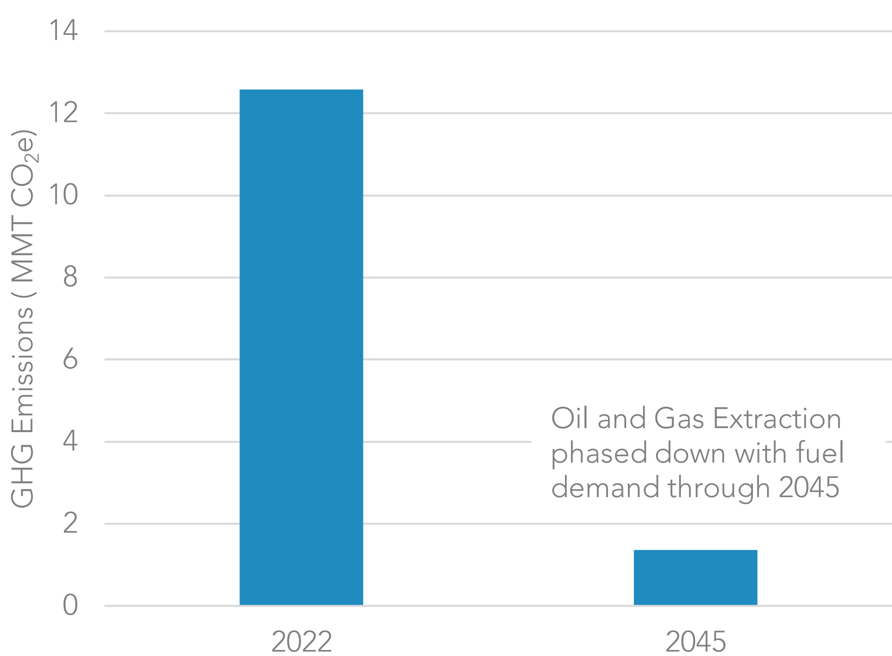
[174] CEC. August 2021. A Primer on California's Pipeline Infrastructure. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2021-08/August_Petroleum_Watch_ADA.pdf.
[175] CEC. March 2020. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.
[176] CalEPA. 2021. Carbon Neutrality Studies: https://calepa.ca.gov/climate/carbon-neutrality-studies/.
[177] Governor Newsom. April 23, 2021. Governor Newsom Takes Action to Phase Out Oil Extraction in California. Press Release. https://www.gov.ca.gov/2021/04/23/governor-newsom-takes-action-to-phase-out-oil-extraction-in-california/.

and jet fuel) in 2045. This demand is primarily for transportation, including for sectors that are directly regulated by the state and some that are subject to federal jurisdiction, such as interstate locomotives, marine, and aviation. As discussed more fully below, while significant GHG reductions from oil and gas extraction could be achieved as demand for fossil fuels is reduced due to strategies in this Scoping Plan, it is not feasible to phase out oil and gas production fully by 2045 given this remaining demand.

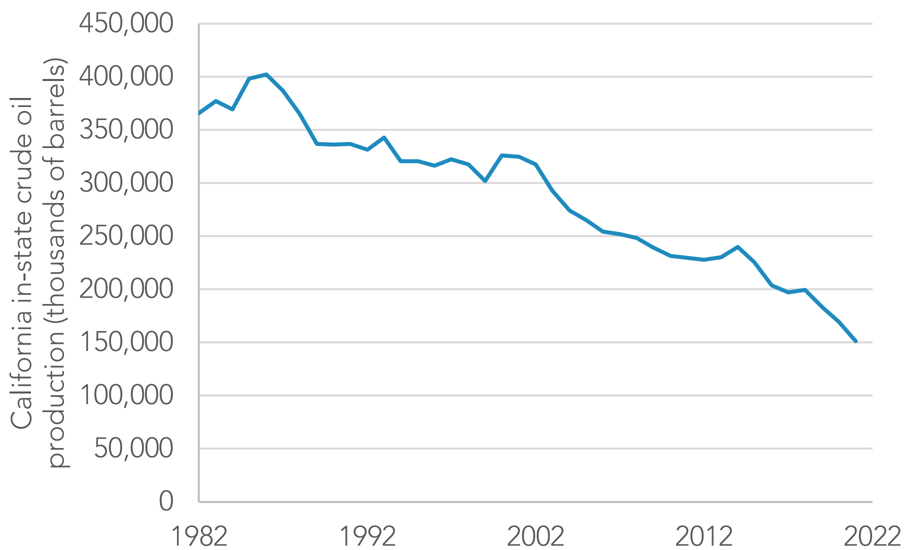
In the Scoping Plan Scenario, with successful deployment of zero carbon fuels and non-combustion technology to phase down petroleum demand, GHG emissions from oil and gas extraction could be reduced by approximately 89 percent in 2045 from 2022 levels if extraction decreases in line with in-state finished fuel demand. If in-state extraction were to be phased out fully, the future petroleum demand by in-state refineries would be met through increased crude imports to the state relative to the Scoping Plan Scenario. AB 32 defines leakage as, “a reduction in emissions in greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.” AB 32 also requires any actions undertaken to reduce GHGs to “minimize leakage.” Increases in imported crude could result in increased activity outside California to extract and transport crude into California. Therefore, our analysis indicates that a full phaseout of in-state extraction could result in GHG emissions leakage and in-state impacts to crude oil imported into the state. Figure 2-6 compares the 2022 emissions from this sector with the modeled results when the sector is phased down with in-state petroleum demand.

**Figure 2-6: Oil and gas extraction sector GHG emissions in 2022 and 2045 when activity is phased down with in-state fuel demand**



According to California Energy Commission (CEC) data used in Figure 2-7, the total oil extracted in California peaked at 402 million barrels in 1986. Since then, California crude oil production has decreased by an average of 6 million barrels per year, to about 200 million barrels in 2020. This steadily decreasing production of crude in California is expected to continue as the state's oil fields deplete.

**Figure 2-7: California in-state crude oil production[178]**




A UC Santa Barbara report estimated that, under business-as-usual conditions, California oil field production would decrease to 97 million barrels in 2045.[179] The business-as-usual model assumed no additional regulations limiting oil extraction in California.

Any crude oil demand by California refineries not met by California crude oil will be met by marine imports of Alaskan and foreign crude.[180] As shown in Figure 2-8, approximately 99 percent of crude imports into California are delivered by marine transportation. The

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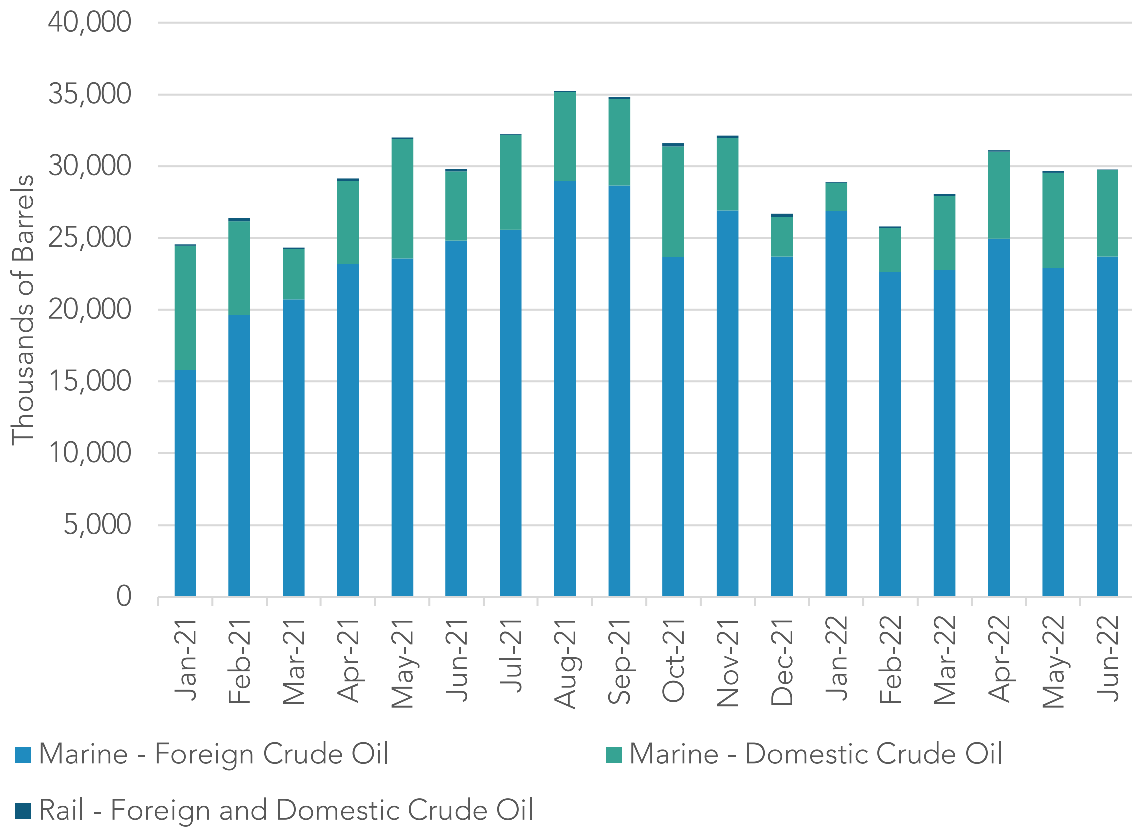
[178] CEC. No date. Oil Supply Sources to California Refineries. Accessed April 21, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/oil-supply-sources-california-refineries.

[179] University of California, Santa Barbara. 2021. Enhancing Equity While Eliminating Emissions in California's Supply of Transportation Fuels.

[180] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf, and CEC. 2020. *Petroleum Watch: What Types of Crude Oil Do California Refineries Process?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

remaining imports occur by rail.[181] There are no pipelines that bring crude oil into California from out of state.[182]

**Figure 2-8: Crude oil imports by transportation type[183]**




Crude oil delivered by marine tankers is delivered to onshore storage tanks and subsequently to refineries via pipeline. Most crude oil produced in California is delivered to California refineries by pipeline. Using historical trends, any increases in imported crude above historic levels would result in increased deliveries through the marine ports. This increased activity could require more infrastructure to store and move larger volumes of crude to the refineries in state.

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[181] CEC. June 2021. Crude Oil Imports by Transportation Type. Accessed March 16, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.
[182] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.
[183] CEC. June 2021. Crude Oil Imports. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.

California refineries import a variety of crude oils to meet refinery needs. California petroleum refineries are generally designed to process relatively heavy crude relative to other U.S. refineries. In 2018, crude inputs to California refineries had an average American Petroleum Institute (API) gravity of 26.18 and an average sulfur content of 1.64 percent. Processing significantly lighter or heavier crude blends would require significant changes to a refinery.[184] Most crude imported from Alaska and the Middle East is relatively light (API gravity > 30) compared to California crude (API gravity < 20).[185] If California crude production is insufficient to meet the demand at California refineries, then California refineries will need access to a similarly heavy source of crude so that the average API gravity of crude remains within their established operating window. South American crude oil imports into California are the heaviest relative to other regions, and therefore they may be the most likely to replace decreased California crude oil supply.[186]

In summary, the modeling indicates that demand for petroleum will persist due to legacy fleets that will not be replaced until end of life. The modeling also shows what the GHG emissions reductions would be if oil and gas extraction activities were phased down in line with the reduction of in-state petroleum demand. Trend data shows that oil and gas extraction already has been on the decline and will continue to decline. It is possible to anticipate the likely regions and types of crude that would be imported to meet in-state petroleum demand if in-state extraction was fully phased out by 2045. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver crude to in-state refineries. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the production and transport of crude to California might increase elsewhere, resulting in emissions leakage.

As the state continues to reduce demand for petroleum, efforts to protect public health for communities located near oil and gas extraction sites must also continue. In October 2021, Governor Newsom directed action to prevent new oil drilling near communities and

[184] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.
[185] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.
[186] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

expand health protections.[187,188] In 2022, the Legislature passed, and the governor signed, SB 1137 to protect communities from existing and any new oil and gas extraction activities through 3,200 foot setbacks.

## Petroleum Refining

In the Scoping Plan Scenario CARB modeled a phasedown of refining activity in line with petroleum demand. Meeting petroleum demand means sufficient availability of finished fuel (gasoline, diesel, and jet fuel). Crude is processed at in-state refineries to produce finished fuel. In response to stakeholder requests,[189] this evaluation focuses on the Scoping Plan Scenario, but with an evaluation of a complete phasedown of refinery operations in state.

The Scoping Plan Scenario results in California petroleum refining emissions of 4.5 $MMTCO_2e$ in 2045; a reduction of approximately 85 percent relative to 2022 levels, which is in line with the decline in in-state finished fuel demand.[190] Emissions from refining can be reduced further through the application of CCS technology, as shown in Figure 2-9. If in-state refining is phased down to zero and the demand for the finished fuels produced by that refining persists, imported finished fuels may be needed to meet the remaining in-state demand.[191] The current data shows unmet demand for liquid petroleum transportation fuels would most likely be met by marine imports. A CEC report notes, "The only way for California to receive large amounts of crude and refined products is by marine."[192]

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[187] Office of Governor Gavin Newsom. 2021. California Moves to Prevent New Oil Drilling Near Communities, Expand Health Protections. https://www.gov.ca.gov/2021/10/21/california-moves-to-prevent-new-oil-drilling-near-communities-expand-health-protections-2/?msclkid=6c0da86bc58e11ecb81cf596d4d8a735.

[188] California Department of Conservation Geologic Energy Management Division. October 2021. Draft Rule for Protection of Communities and Workers from Health and Safety Impacts from Oil and Gas Production Operations. https://www.conservation.ca.gov/calgem/Pages/Public-Health.aspx?msclkid=45660232cf2511ecb1c56119097e3b0c.

[189] California Environmental Justice Alliance. October 22, 2021. Comment on 2022 Scoping Plan Update - Scenario Inputs Technical Workshop. https://www.arb.ca.gov/lists/com-attach/68-sp22-inputs-ws-WzhdPlI5AjACW1Qx.pdf.

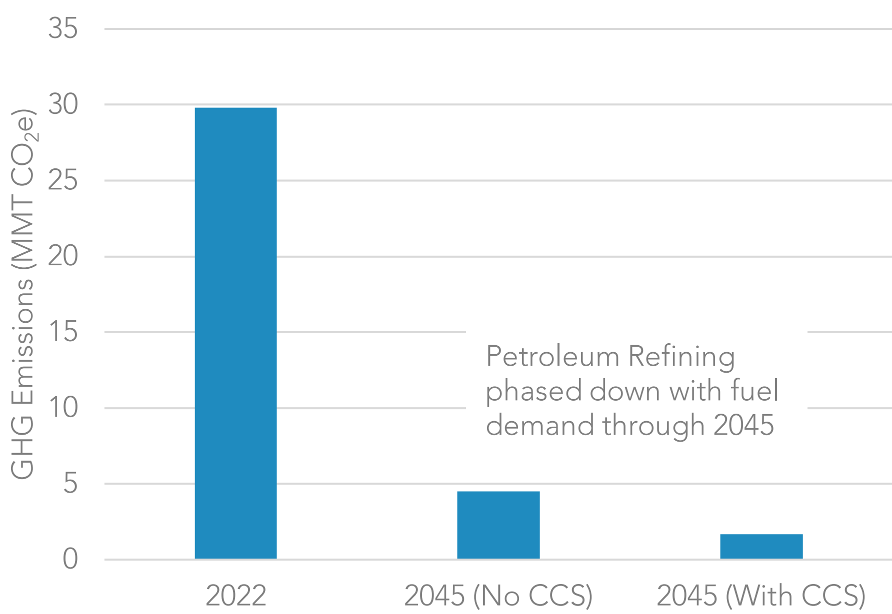
[190] This reduction in demand does not assume any need for ongoing operations to support exports to neighboring states.

[191] If demand assumes an ongoing need to support exports to neighboring states, the residual demand would require a five-fold increase in finished fuel imports.

[192] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

There are currently no pipelines capable of bringing refined products to the state, and rail imports of refined products have historically made up less than 1 percent of all imports.[193] Significant increases in marine imports would likely require significant reconfiguring, retrofitting, or replacement of crude pipelines and storage tanks at current marine terminals, and possible reconfiguring of existing finished fuel infrastructure to account for changes in volumes and locations of supply points.

**Figure 2-9: Petroleum refining sector GHG emissions in 2022 and 2045 (with and without CCS) when activity is phased down with fuel demand**




If California's finished fuel demand is not met by continued refining activity in California, the state would need to import finished fuels to meet the ongoing demand. This would likely result in a two- to five-fold increase in the number of finished fuel ship deliveries to marine terminals. Marine tankers delivering refined products are often much smaller than crude oil tankers, so changes in fuel use and emissions cannot be easily estimated from the change in both the type and the number of ship deliveries.[194]

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[193] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.
[194] Personal communication with CEC staff, March 2022; U.S EIA. 2017. *World Oil Transit Chokepoints*. 3. https://www.eia.gov/beta/international/regions-topics.php?RegionTopicID=WOTC.

If refining ceased in California, the rail and marine deliveries currently needed to support both refining processes and the export of waste products, such as petroleum coke, would cease.

In summary, the modeling indicates that demand for petroleum will persist through 2045. The modeling also shows what the GHG emissions reductions would be if refining activities were phased down in line with the reduction in in-state petroleum demand. CCS can further reduce emissions for this sector. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver finished fuel across the state, if in-state refining were fully phased down by 2045. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the refining and transport of finished fuel to California might increase elsewhere, resulting in emissions leakage.

## Progress Toward Achieving the Accelerated 2030 Target

The 2017 Scoping Plan laid out a path to achieving the SB 32 target of at least a 40 percent reduction of GHG emissions below 1990 levels by 2030 that focused on reducing emissions in the state and was technologically feasible and cost-effective, reflecting statutory direction. Many of the programs to achieve the 2030 target increased in stringency beginning January 1, 2021. However, the 2030 target must be increased to help achieve the deeper reductions needed to meet the state's statutory carbon neutrality target specified in AB 1279 and Executive Order B-55-18.

Starting in 2020 and extending into 2022, the COVID-19 pandemic impacts reverberated across the globe in a multitude of ways, including the devastating loss of millions of lives. The pandemic also had a significant impact on GHG emissions by virtue of its impact on global economies and lifestyle changes for Californians, with extended work and school disruptions. Thus, assessing our progress toward meeting our SB 32 target is confounded by the unprecedented nature of the pandemic. Nevertheless, an assessment of progress toward the 2030 target is critical, in particular the accelerated 2030 target called for in this Scoping Plan, since achieving the accelerated 2030 target would make the state well positioned to achieve its carbon neutrality goals and bring critical near-term air quality benefits to address historical and ongoing disparities in access to healthy air. Because there is only one year of data available for this decade, the analysis takes a prospective look using projected emissions over the remainder of this decade.

Estimating GHG emissions in 2030 requires projecting the effect of policies or measures that are currently deployed and undergoing implementation. Table 2-4 shows three distinct estimates of GHG emissions in 2030 that were created at different times and used different modeling approaches.

**Table 2-4: Estimates of 2030 GHG emissions**

| Scenario Description | 2030 GHG Emissions ($MMTCO_2e$) |
| --- | --- |
| 2017 Scoping Plan: the projected outcome from implementing policies identified in the 2017 Scoping Plan that was approved by the CARB Board in December 2017. | 320 |
| Reference Scenario: the assessment of current trends and expected performance of policies identified in the 2017 Scoping Plan, as of February 2022, using the PATHWAYS model (E3). | 305 |
| Reference Scenario (Rhodium): the analysis of projected emissions from 2021 to 2030 from state and federal policies implemented as of July 2022, including the estimated impact of the Inflation Reduction Act and Advanced Clean Cars II using RHG-NEMS and other Rhodium Taking Stock 2022 methods (https://rhg.com/wp-content/uploads/2022/07/Taking-Stock-2022_US-Emissions-Outlook.pdf). | 324 |

These three estimates of 2030 GHG emissions differ, which is expected. The estimates reflect different outcomes of the current and future impact of policies and measures. They also vary due to fundamental differences in the way these models work. For example, PATHWAYS is an economy-wide, scenario-based GHG accounting tool that tracks energy demands and supplies in line with scenario assumptions and is benchmarked to historical values. RHG-NEMS optimizes both the supply and demand sides of the energy system while factoring in consumer constraints and dynamic economic and energy systemwide feedback. Importantly, while these point estimates give the appearance of certainty and accuracy, there is significant uncertainty in future emissions projections that is documented thoroughly in each of the three emissions scenarios described above. No model can predict the future given unforeseen factors such as notable economic swings and implementation delays for programs. However, the range of emissions estimates provides a useful indication of possible outcomes from successful implementation of policies and measures.

An important source of uncertainty is the impact of delayed implementation of policy measures and market actions. The successful rate of deployment of clean technology and fuels—including consumer adoption patterns, economic recovery from the pandemic, and the permitting and build-out of necessary new assets and reuse of existing assets to produce and deliver clean energy—is essential to reach GHG emission reduction targets. Any delays will only increase GHG emissions in 2030.

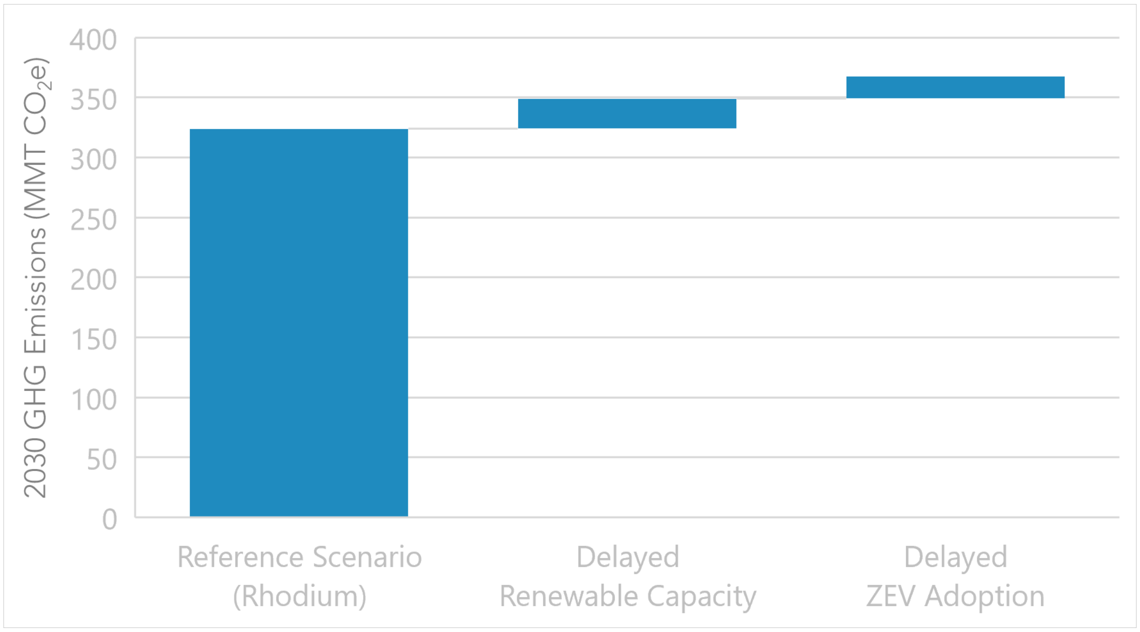
It is important to note that incentives, carbon pricing, and regulations all can result in similar types of responses including, but not limited to:

- Build-out of clean energy and infrastructure
- Deployment of clean technology
- Reduced demand for fossil energy
- Efficiency improvements

As such, the uncertainty analysis discussion focuses on implementation (technology and infrastructure deployment), and not any specific programs or policies. It is successful implementation that must ultimately happen for emissions reductions to be realized.

The uncertainty analysis described in Appendix J (Uncertainty Analysis) quantifies the impact of delayed permitting and building of renewable generation and transmission in the power sector and delayed adoption of ZEVs across all vehicle fleets in the transportation sector. The Reference Scenario (Rhodium) estimates emissions in 2030 to be 324 MMTCO2e. A five-year delay in renewable capacity would increase emissions by 8 percent in 2030 (25 MMTCO2e) relative to the Reference Scenario. If similar delays in clean energy production and deployment occur in other sectors, a larger increase in emissions relative to the reference scenario would be expected, jeopardizing the state's ability to achieve the 2030 target. Similarly, a delay in consumer adoption of zero emission vehicles (LDV, MDV, HDV) would increase emissions by 6 percent in 2030 (19 MMTCO2e) relative to the Reference Scenario. Delays in transitioning to electric equipment and appliances in homes and businesses would also lead to increased emissions in 2030. Figure 2-10 illustrates the impact on projected emissions in 2030 associated with delayed renewable capacity and delayed transportation vehicle electrification.

**Figure 2-10: Impact of delayed implementation on 2030 GHG emissions**[195]




Appendix J (Uncertainty Analysis) includes additional details on the assumptions and model used for the uncertainty analysis and the risks to achieve the emissions reductions from 2022 to 2030 that are anticipated in the Scoping Plan Reference Scenario. While the analysis focuses on renewable capacity and transportation, the analysis identifies a common set of themes that can impact emissions reductions across economic sectors, including permitting, technology availability, and consumer adoption. The impact of delayed emissions reductions will vary by sector and by the specific policy at risk of delay.

We give these quantitative examples of the impact implementation delays can have on GHG reductions, but almost every economic sector will have the need for permitting to enable at least a 40 percent reduction below 1990 levels. If we consider the increased ambition of the Scoping Plan Scenario, which identifies an accelerated 2030 target, the same types of uncertainty manifest themselves in successful implementation of the Scoping Plan Scenario, with the added need for CCS and CDR and a need to grow other energy sectors such as hydrogen.

[195] The implementation delay scenarios were modeled separately and do not necessarily reflect the combined impact of delayed renewable capacity and transportation vehicle electrification.

## Cap-and-Trade Program Update

Since the adoption of the first Scoping Plan in 2008, carbon pricing in the form of a Cap-and-Trade Program has been part of the portfolio to achieve the state's GHG reduction targets, and it will remain critical as we work toward carbon neutrality. This section provides an update on the program and its role in achieving the 2030 target.

The Cap-and-Trade Program first came into effect in 2012, under AB 32, and included declining allowance caps through 2020. In 2017, AB 398[196] was passed by a supermajority in the Legislature and included prescriptive direction on the design of the program from 2021 through 2030. The AB 398 Cap-and-Trade Program came into effect on January 1, 2021, and it included the following changes:

- Doubling of stringency with an annual cap decline of 4 percent per year from 2021–2030
- AB 398 price ceiling
- AB 398 redesigned allowance price containment reserve with two tiers
- AB 398 100 percent leakage assistance factor for industry
- AB 398 lower offset limits: Usage limit cut from 8 percent to 4 percent, and half of offsets must provide direct benefits to California

The reduction in the role of offsets in the program was in recognition of ongoing concerns raised by environmental justice advocates regarding the ability of companies to use offsets for compliance instead of investing in actions on site to reduce GHG emissions that could also potentially reduce criteria or toxic emissions.[197,198] Note that data show the relationship between facility emissions of GHGs and co-pollutants is highly variable by sector and pollutant.[199] Changes to the allowance price containment reserve and the addition of the price ceiling were included to ensure protections against price spikes in the program, while the changes to the leakage assistance factors were to ensure the maximum protection against leakage in the program. The original design of the program included an auction floor price that increases by 5 percent plus inflation each year, and

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[196] Assembly Bill 398 (Garcia, Chapter 135, Stats. of 2017). California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

[197] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

[198] The OEHHA report also found that companies that use the most offsets often own the facilities that contribute to local $PM_{2.5}$ exposure. However, there was no causal relationship found to indicate that implementation of the Cap-and-Trade Program was contributing to increases in local air pollution. Also see: CARB. FAQ Cap-and-Trade Program. https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

[199] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

that escalation factor is retained in the post-2020 program and is also applied to the allowance price containment reserve and price ceiling. These features, combined with the self-ratcheting mechanism for unsold allowances at auctions,[200] help to ensure the program is able to handle periods of high and low demand for allowances while continuing to ensure a steadily increasing price signal for regulated entities to invest in GHG reduction technologies.

As a result of achieving the 2020 target several years earlier than mandated by law, there are unused allowances in circulation. CARB estimated the amount to be approximately 310 million allowances after the conclusion of the third compliance period (2018–2020).[201] AB 398 had also called for a similar analysis, which was completed in 2018.[202] This bank represents approximately 5 percent of the total number of vintage 2013–2030 allowances issued within the joint market. This bank of allowances can only remain banked if year-over-year the covered emissions are declining by 14 MMT. If the annual decline in actual emissions is less than 14 MMT, regulated entities will need to use the banked allowances to cover their compliance obligations. It is likely that the existing bank of 310 million allowances will be needed over the early part of this decade and will be exhausted by the end of the decade. During the same period, prices for allowances will continue to increase at least 5 percent plus inflation year-over-year, sending a steadily increasing price signal to spur investment in onsite reductions for covered entities.

With the passage of AB 1279, the state has a statutory target to achieve carbon neutrality no later than 2045. This Scoping Plan demonstrates that planning on a longer time frame for the new carbon neutrality target means we must accelerate our near-term ambition for 2030 in order to be on track to achieve our longer-term target. CARB will use the modeling for this Scoping Plan to assess what changes may be warranted to the Cap-and-Trade or other programs to ensure we are on track to achieve an accelerated 2030 target. Since the original adoption of the Cap-and-Trade regulation, the program has been amended eight times through a robust public process. Moreover, then-California Environmental Protection Agency Secretary Jared Blumenfeld testified at a Senate hearing in 2022 that CARB will report back to the Legislature by the end of 2023 on the status of the allowance supply with any suggestions on legislative changes to ensure the number of allowances

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[200] The self-ratcheting mechanism temporarily removes unsold allowances from the market until either sufficient demand manifests for two consecutive auctions and they are incrementally reintroduced at future auctions, or they are permanently removed from general circulation if demand remains low.
[201] CARB. 2022. BR 18-51 Cap-and-Trade Allowance Report. Attachment A. *https://ww2.arb.ca.gov/sites/default/files/cap-and-trade/Allowance%20Report_Reso18_51.pdf*.
[202] CARB. 2018. Staff Report: Initial Statement of Reasons: Proposed Amendments to the Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation. September 4. *https://www.arb.ca.gov/regact/2018/capandtrade18/ct18398.pdf?_ga=2.134288305.1735610122.1664813952-1100516233.1657841496*.

is appropriate to help the state achieve its 2030 target of at least 40% below 1990 levels. As part of that status update, CARB will also provide information on any potential program changes that may be needed to allowance supply to help achieve an accelerated target for 2030 identified in this Scoping Plan as necessary to achieve carbon neutrality no later than 2045. Engaging in this process in 2023 will allow for the consideration of this Scoping Plan, inclusion of additional data points for the second year of operation of the AB 398-designed program (which only came into force in January 2021), and an opportunity to hold public workshops.

It is also worth noting that the COVID-19 pandemic had significant impacts on economic activity in California and elsewhere.[203] Emissions were significantly lower in 2020 due to the impacts of the global pandemic. There is an expectation that emissions will increase as the economy recovers and behaviors continue to shift from the impacts of the ongoing pandemic. As a result, 2020 should be regarded as an outlier in the emissions trends. This scenario of increasing emissions is similar to what happened in the first compliance period for Cap-and-Trade, where the state economy was recovering from the Great Recession and does not correlate to a problem with the structure of this program or other programs that cover emissions related to the manufacturing or transportation sectors. In any assessment of this and other programs, it is essential to consider external factors such as economic activity and availability of zero carbon energy such as hydropower, among others.

To better understand the role of the Cap-and-Trade Program in achieving the 2030 target, Table 2-5 compares the 2030 GHG emissions estimates from the three reference scenarios described in Table 2-4. The 2017 Scoping Plan projection is from the PATHWAYS model for the Scoping Plan Scenario approved by the Board in late 2017. It excludes the contribution of the Cap-and-Trade Program, without any consideration of uncertainty factors (i.e., a characterization of the uncertainty that a given GHG reduction measure included in the 2017 Scoping Plan will actually achieve the GHG reductions it is projected to deliver). The Reference Scenario represents what GHG emissions would look like if we did nothing beyond the existing policies that are required and already in place to achieve the 2030 target; this scenario is based on the recent PATHWAYS modeling, excluding the contribution of the Cap-and-Trade Program, and without any consideration of uncertainty factors. It indicates that GHG emissions will be lower over this decade than originally projected when the 2017 Scoping Plan was approved. The

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[203] CARB. November 4, 2021. Mandatory Greenhouse Gas Reporting - 2020 Emissions Year Frequently Asked Questions. https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2020mrrfaqs.pdf?_ga=2.264251343.1760432228.1650736660-1644197524.1577749754.

Reference Scenario (Rhodium) which also does not include uncertainty bounds, is the modeling used for the uncertainty analysis above.

Importantly, PATHWAYS is not able to explicitly model a carbon pricing policy, and therefore the Cap-and-Trade Program is not represented in the 2017 Scoping Plan or the Reference Scenario. Carbon pricing is included in RHG-NEMS, which reflects state and federal policies included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2022 and the National Energy Systems Model (NEMS), which is the basis for RHG-NEMS.[204]

As detailed in EIA's documentation, California's Cap-and-Trade Program is represented through increased energy prices, which flow across economic sectors.[205] However, many of the emissions covered by the California Cap-and-Trade Program are not energy- and fuel-related emissions. Given that, the energy systems model RHG-NEMS was used to model the impact of California Cap-and-Trade on the energy system. However, RHG-NEMS does not explicitly model the entire program, which includes non-energy related emissions from the industrial, agricultural, waste, and transportation sectors.

[204] U.S. EIA. 2022. *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2022.* March. https://www.eia.gov/outlooks/aeo/assumptions/pdf/summary.pdf.
[205] U.S. EIA. 2022. Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

**Table 2-5: Comparison of 2017 Scoping Plan and two Reference Scenarios**

| | 2030 GHG Emissions ($MMTCO_2e$) (2017 Scoping Plan) | 2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario) | 2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario-Rhodium) |
|---|---|---|---|
| **Reference Scenarios** | 320 | 305 | 324 |
| **Gap to Accelerated 2030 Target under the Scoping Plan Scenario (226)**[206] | 94 | 79 | 98 |

Under the Scoping Plan Scenario, in 2030 California emissions are anticipated to be 48% below 1990 levels. This represents an acceleration of the current SB 32 target of a 40% reduction below 1990 levels. Table 2-5 includes the gap between the different reference scenarios and the accelerated 2030 target achieved under the Scoping Plan Scenario. It also shows that depending on the modeling, there are a range of potential emissions levels in 2030 prior to accounting for the full impact of the Cap-and-Trade Program on emissions. That range is from 305 to 324 $MMTCO_2e$ in 2030. That represents a 19 $MMTCO_2e$ spread, or about 8.4 percent of the accelerated 2030 target of 226 $MMTCO_2e$. Importantly, none of these scenarios includes all of the actions identified in the Scoping Plan Scenario for this Scoping Plan; many of those actions, such as SB 596, CCS, and a more stringent LCFS program, will only begin to happen in this decade, and their contributions toward meeting the accelerated 2030 target are therefore not included in the reference scenarios. The actual emissions for the remainder of this decade will therefore likely be lower than in each of the scenarios in Table 2-5 once policies and regulations are in place to support an accelerated 2030 target. However, the degree of this difference between actual and projected emissions will differ across the modeled reference scenarios.

[206] Table 3 from the 2017 Scoping Plan included a range of 34 to 79 $MMTCO_2e$ for reductions needed from the Cap-and-Trade Program to achieve a 2030 target of 40 percent below 1990 levels.

Regardless of the uncertainty and differences in the models, it is clear additional GHG reductions must happen over this decade to achieve an accelerated 2030 target. This will require an evaluation of all major programs to assess the need to increase their stringency between now and 2030. As the actual reductions from non-Cap-and-Trade Program measures increase, California will be less reliant on the Cap-and-Trade Program to “fill the gap” to meet an accelerated 2030 reduction target. For example, CARB is developing a proposal to increase the stringency of the LCFS program for 2030, the recently adopted Advanced Clean Cars II regulation is more stringent than modeled for the 2030 40 percent target in the 2017 Scoping Plan, and SB 596 requires specific reductions in the cement sector over this decade and beyond. However, we also know we are not on track to achieve the VMT reduction called for in the 2017 Scoping Plan and will need to double down to achieve the even more ambitious target called for in the Scoping Plan Scenario. Also, we will need additional actions over the coming years to reduce short-lived climate pollutants to meet the emission reductions called for in SB 1383.

Collectively, any additional legislation or prescriptive policies for sectors, delays in successful implementation of non-Cap-and-Trade programs and policies, increases in incentive program funding, and delays in economic recovery from the pandemic will continue to affect the role the Cap-and-Trade Program will need to play over this decade to meet the state’s GHG reduction obligations. In summary, the Cap-and-Trade Program must continue to be able to scale across a range of possibilities. With passage of AB 1279 and the need to accelerate the 2030 target, CARB will initiate a public process to utilize the modeling results from this Scoping Plan, specifically the Scoping Plan Scenario, to evaluate and potentially propose changes to the design of the Program, including the annual caps. This process will ensure that the Program supports an increased ambition for 2030 while retaining the ability to scale as other factors, such as changing economic conditions and implementation of non Cap-and-Trade programs, impact the actual emissions at the sources covered by the Program. Any changes to the Program must continue to support a well-designed system that continues to send a steadily increasing price signal, minimizes for leakage, reduces emissions in the covered sectors toward the state’s targets, is cost-effective and technologically feasible, and avoids energy rate spikes. Importantly, the Program should support air quality benefits, especially in overly burdened communities, and not exacerbate existing air quality disparities.

# Chapter 3: Economic and Health Evaluations

This chapter provides two approaches for quantifying the economic and health outcomes of the Scoping Plan Scenario. One approach is to consider the combined impact of all measures[207] in a scenario. The other approach is required by AB 197, where each measure within a scenario is evaluated independently. In addition to these two evaluation approaches, this chapter also includes a discussion of the Public Health implications for the Scoping Plan Scenario, an overview of the Climate Vulnerability Metric, and the Environmental Analysis conducted in accord with the California Environmental Quality Act (CEQA).

It is important to note that all of the analyses in this chapter use a variety of data sources, but because the modeling is economy-wide at the state level, none of them produce community specific detail outputs. The AB 32 GHG Inventory Sector analysis relies on PATHWAYS data at the state level that is proportionally applied across all regions of the state to translate changes in state level fuel combustion to local level changes. The NWL analysis similarly utilizes a variety of data sources and a suite of models that produce data that are scaled up to the statewide level. All of the models, except the Wildland Urban Interface (WUI) defensible space model, which is conducted at the county level, create aspatial projections that are not applicable at the community level.

## Economic Analysis

As part of the process to develop this Scoping Plan, alternative scenarios that transition energy needs away from fossil fuels and achieve carbon neutrality no later than 2045 were developed. Alternative scenarios that assess the impact of different land management strategies on carbon stocks in NWL were also developed. These alternatives are described in Appendix C (AB 197 Measure Analysis). The following sections describe the Scoping Plan Scenario in terms of direct cost, the economy, employment, and health outcomes.[208]

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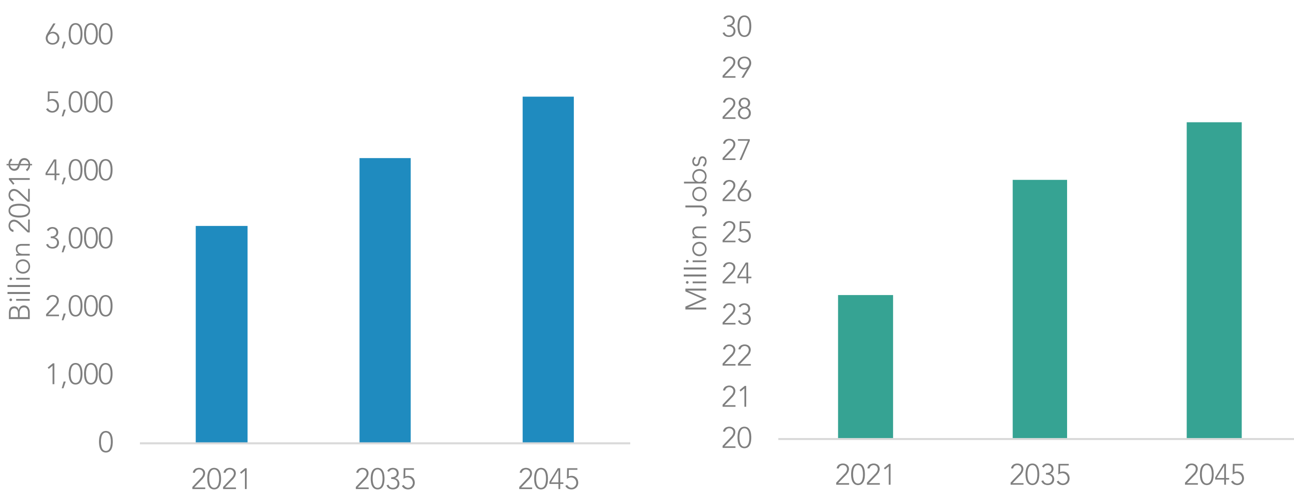
[207] AB 197 calls for the evaluation of “measures.” This Scoping Plan treats each action and its variants on stringency as measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative and the Scoping Plan Scenario. The modeling assumptions for the Scoping Plan Scenario are summarized in Table 2-1.

[208] For the Draft 2022 Scoping Plan Update, achieving carbon neutrality in 2035 and 2045 was evaluated. The AB 32 GHG Inventory sector direct cost, the economy, employment, and health outcomes were assessed in those years. Similarly, the Scoping Plan Scenario assessments that are presented in this chapter were made for years 2035 and 2045.

The California economy is growing, and it is projected to continue to grow about 2 percent each year, from $3.2 trillion in 2021 to $5.1 trillion in 2045, as shown in Figure 3-1. Similarly, employment in California is anticipated to grow 0.7 percent per year, from 23.5 million jobs in 2021 to 27.7 million jobs in 2045. It is in this context, termed the *Reference Scenario,* that CARB evaluates the Scoping Plan Scenario in terms of its impact on economic growth and employment. The projections shown in Figure 3-1 were produced by CARB to evaluate the incremental impact of regulations.

**Figure 3-1: Projected California gross state product (left) and employment growth (right) from 2021 to 2035 and 2045**




*Source: California Air Resources Board*

Transitioning away from fossil fuels to alternatives and increasing action on NWL will affect employment opportunities, household spending, businesses, and other economic aspects of our lives. Sectors expected to see growth include renewable electricity and hydrogen production, while other sectors may shrink. The deployment of clean technology may require higher upfront costs for things like heat pumps and induction stoves, but those could be offset by energy efficiency savings. Employment and economic development in NWL-related industries and sectors are expected to increase as land management actions increase, especially for the Forestry sector (in which a significant increase is called for under the Scoping Plan Scenario). The net impact of these actions on employment and jobs is presented in this chapter.

## Estimated Direct Costs

One key metric is the direct cost, or net investment, reflecting any savings that result from actions. Similar approaches were used to estimate direct costs for the AB 32 GHG Inventory sectors and for the NWL, as described in this section.

## AB 32 GHG Inventory Sectors

Transitioning away from fossil fuels requires investment in new equipment and infrastructure throughout the economy. It involves developing the capacity to produce fuels and electricity from renewable sources rather than producing fossil energy. This transition also takes time. One approach is to eliminate combustion of fossil fuels by replacing all equipment in a specified year. Another approach is to establish a future point at which all sales of new equipment rely on alternative energy sources and allow the transition to occur over time as equipment is replaced upon its end of life.

To evaluate the investment required through 2045, the PATHWAYS model was used to represent equipment stock and its turnover to non-fossil fuel alternatives over time. The annualized, incremental cost of infrastructure in excess of the annualized cost of the Reference Scenario[209] was computed for each year from 2022 through 2045. These costs were computed by first taking the absolute cost in each year—which includes both new equipment investment and also expenditures on energy, operations, and maintenance in each year—and then levelizing the costs (in the same way car or house payments are annualized or spread out over time) to arrive at an annualized cost. Fuel savings, and resulting cost savings, associated with changing energy demand—from gasoline to electricity for vehicles, for example—are included as a result of this methodology. Carbon dioxide removal includes DAC technology powered primarily by off-grid solar, BECCS to produce hydrogen or other fuels, and NWL sequestration, as discussed in Chapter 2.[210]

Figure 3-2 shows the stock investment cost, fuel/efficiency savings, and CDR cost. The Scoping Plan Scenario allows end-of-life transition of equipment. The cost of investing in new equipment is partially offset by savings associated with efficiency gains and reduced demand for fuels like gasoline. This is particularly relevant in the transportation sector, which leads to the majority of savings in 2045 in the Scoping Plan Scenario, which models near complete electrification of transport relying only on end-of-life replacement of vehicles. Appendix H (AB 32 GHG Inventory Sector Modeling) includes additional detail on direct costs in each sector and how costs change over time.

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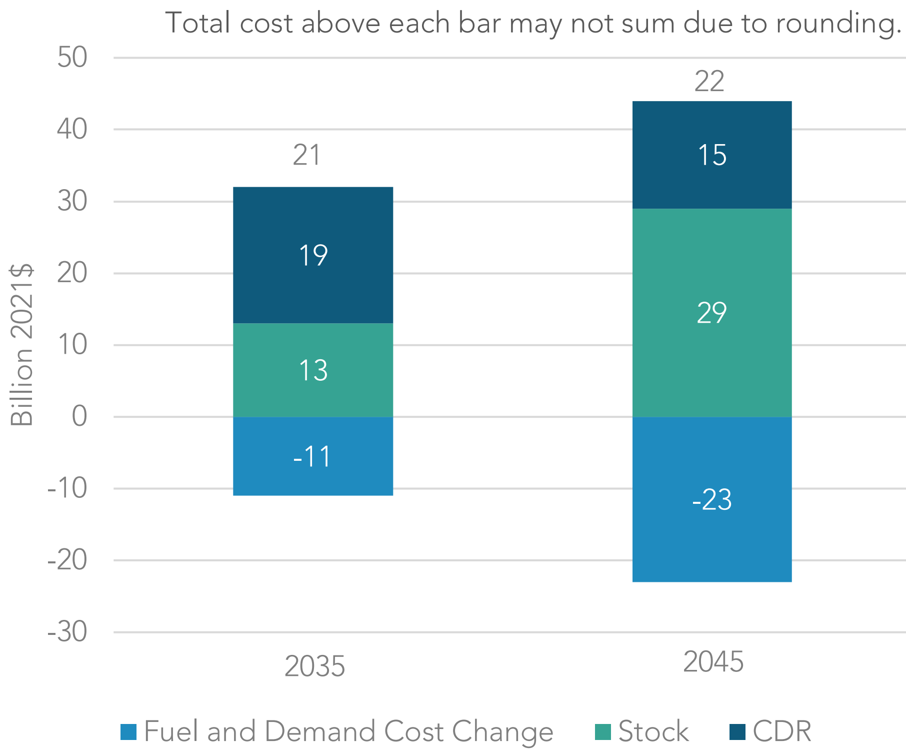
[209] The Reference Scenario described in Chapter 2 and in Appendix H (AB 32 GHG Inventory Sector Modeling) was the basis for the direct cost comparison.

[210] The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero-carbon options consistent with the carbon neutrality targets in this Scoping Plan. The economic analysis associated the investment in DAC with the solar industry for consistency with the carbon neutrality targets.

**Figure 3-2: Cost and savings relative to the growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)**




## Natural and Working Lands

For NWL, the direct costs of each management strategy were estimated using available academic literature, monitoring and reporting data, survey data, and cost data from existing subsidy programs on the per acre cost of implementing the management strategy. These cost data, in combination with the acreage of each management strategy under the scenarios, provided estimates of the overall direct cost to either the government or the private sector. The direct costs are independent of the policy lever used to implement the action and do not include many important benefits and externalities of the actions. They are assumed to be constant for each scenario and into the future. Avoided or secondary costs, such as those from reductions in wildfire suppression expenses, are not included. Appendix I (NWL Technical Support Document) includes additional direct cost details.

Table 3-1 includes the direct cost estimates for the Scoping Plan Scenario compared to the Reference Scenario.[211] Direct costs for the NWL sector are expected to be significant due to the ambitious level of action for each land type.

**Table 3-1: Cost and savings relative to a growing California economy for the Scoping Plan Scenario (NWL)**

| Measure | Scoping Plan Scenario: Average Direct Annual Cost, 2025–2045 (millions $/year) |
|---|---|
| **Forests / Shrublands / Grasslands** | 1,780 |
| **Annual Croplands** | 284 |
| **Perennial Croplands** | 4 |
| **Urban Forest** | 4,230 |
| **Wildland Urban Interface (WUI)** | 114 |
| **Wetlands** | 28 |
| **Sparsely Vegetated Lands** | 4 |
| **Totals** | 6,460 |
| Note: Table values may not add to total due to rounding. | |

CARB estimates that all jurisdictions, including private landowners, currently spend approximately $4 billion dollars annually on planting, maintenance, sidewalk repair, tree removal, and other expenses related to urban forests, and that reaching the theoretical maximum tree cover would require increasing that spending by a factor of 20. The cost of the Scoping Plan Scenario is predominantly a mix of urban forests and forests, shrubland, and grasslands spending.

[211] The Reference Scenario described in Chapter 2 and in Appendix I (NWL Technical Support Document) was the basis for the direct cost comparison.

## Economy and Employment

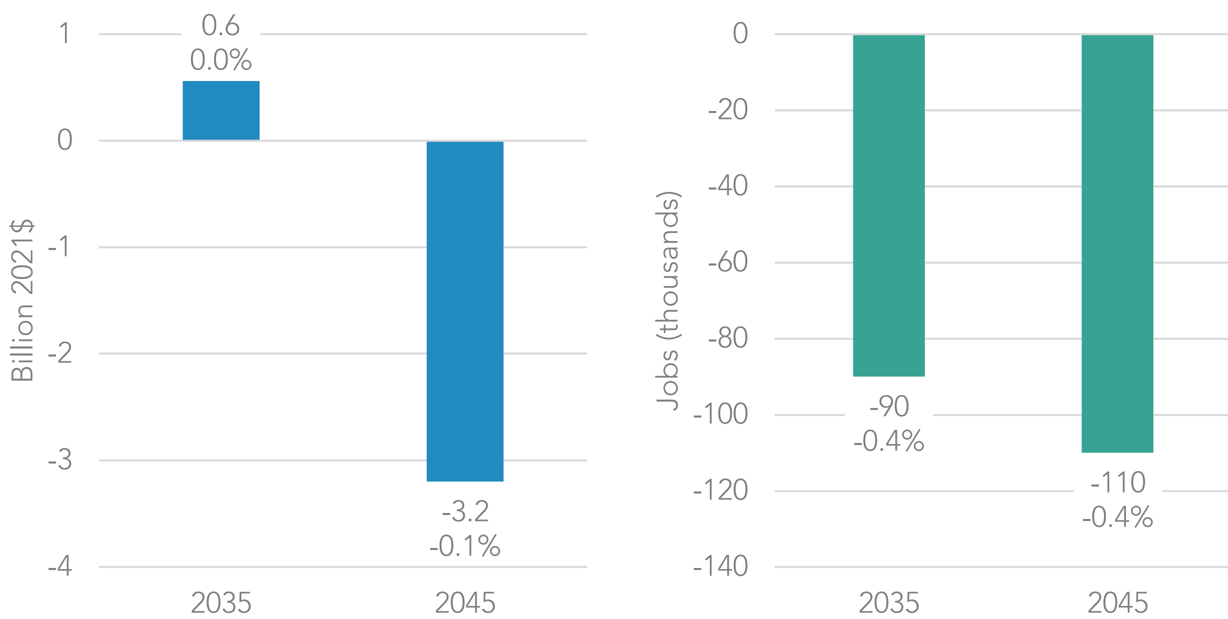
Two different models were used to estimate the overall impact that investing in a transition away from fossil fuels and in our NWL may have on the growing California economy. The transition away from fossil fuels was evaluated using the IMPLAN economic analysis model. The NWL investments were evaluated using the REMI PI+ economic model. These models provide similar outputs relative to the same economic and employment forecasts used to develop a Reference Scenario for use in each model.

### AB 32 GHG Inventory Sectors

To estimate the overall impact that investing in a transition away from fossil fuels may have on the California economy, CARB used the IMPLAN model. Additional detail regarding the model, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). The IMPLAN model is a multisector representation of private industries in the U.S. economy that maps economic relationships across industries, households, and governments. This model translates direct costs and savings associated with transitioning away from fossil fuels with indirect effects such as wages, purchases of goods and services, business tax impacts, and supply chain effects. In addition, the induced effects of household purchases, local and import purchases, wages paid, and household tax impacts are estimated. This comprehensive assessment of the interactions between capital investment in fossil fuel alternatives and household purchases provides an indication of the response of the California economy to the Scoping Plan Scenario.

The Scoping Plan Scenario results in a small impact on the Gross State Product (GSP) and employment relative to the Reference Scenario, as shown in Figure 3-3. Economic growth is largely unaffected by the Scoping Plan Scenario in 2035 and slowed by 0.1 percent in 2045. Employment growth is also slowed a small amount, 0.4 percent in 2035 and in 2045, and employment still grows. Assuming annual growth rates of 0.7 percent means there would be more than 193,000 additional jobs in 2045.

**Figure 3-3: Gross state product (left) and employment (right) relative to a growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)**




California households will see increased costs from the purchase of new capital stock and savings from reduced spending on fuel, as shown in Figure 3-2. Households also will face increased costs associated with CDR, costs associated with energy efficiency measures, and commercial stock purchases—all of which are assumed to be passed directly to consumers. The impact to California households, however, is not limited to these direct costs, as changes in relative prices, employment, and wages can affect household well-being. Personal income, which captures the direct, indirect, and induced impacts, is a metric commonly used to evaluate the impact of policies on households.

Personal income in California is projected to grow from $2.7 trillion in 2021 to $3.6 trillion in 2035 and $4.4 trillion in 2045. Household projections are based on California Department of Finance population projections, which estimate the state's population to grow an average of 0.3 percent each year from 2021 to 2045.[212] California households are projected to increase from 13.3 million in 2020 to 14.6 million in 2035 and 15.0 million in 2045.

[212] California Department of Finance. Population Projections (Baseline 2019). https://dof.ca.gov/forecasting/demographics/projections/.

While the transition away from combustion of fossil fuels will improve air quality for all Californians (and even, more so in overly burdened communities), the economic impacts of the Scoping Plan Scenario are unlikely to be equal among Californians. Table 3-2 presents the change in income by household income group relative to the Reference Scenario in 2035 and 2045. While in 2035 there is a net decrease in personal income of $600 million, total income for households that make less than $100,000 per year is estimated to decline by $4.1 billion dollars, and the total income for households that make more than $100,000 per year will increase by $3.5 billion under the Scoping Plan Scenario. In 2045, although there is no net change in personal income across all California households, results vary by income level. Total income for households that make less than $100,000 per year are estimated to decline by $5.3 billion dollars, while the total income for households that make more than $100,000 per year will increase by $5.3 billion under the Scoping Plan Scenario.

**Table 3-2: Income Impacts by California household income group in 2035 and 2045 for the Scoping Plan Scenario (AB 32 GHG Inventory Sectors)**

| Household Income Group ($2021) | Percentage of 2021 California Households[213] | Change in Income (Billion $2021) | |
|---|---|---|---|
| | | 2035 | 2045 |
| **Less than $50,000** | 30 | -2.9 | -3.9 |
| **$50,000 to $100,000** | 27 | -1.2 | -1.4 |
| **$100,000 to $200,000** | 28 | 2.5 | 4.0 |
| **More than $200,000** | 15 | 1.0 | 1.3 |
| **Total** | 100 | -0.6 | 0.0 |

[213] U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.

In addition to income level, there is likely to be an impact to California personal income that varies based on race/ethnicity.[214] Table 3-3 shows the percentage of households within each income group based on eight race/ethnicity categories identified in the American Community Survey 2021. As shown in Table 3-2, households in lower income groups are anticipated to see negative impacts, while households in higher income groups are anticipated to see positive impacts from the Scoping Plan Scenario in both 2035 and 2045. Because more than 60% of households in the race/ethnicity categories of Hispanic, Black alone, Native Hawaiian (HI) or Pacific Islander, American Indian or Alaskan Native, Other, and Two or More make less than $100,000 per year, these populations generally are likely to experience reduced income. White and Asian households will generally experience both increased and decreased income because these households are distributed more evenly across all four income groups.

The state recognizes the need to ensure that accessibility to clean technology and energy do not further exacerbate health and opportunity gaps for low-income households and communities of color. The Climate Change Investments program exceeds the statutory minimums to invest in projects to benefit disadvantaged communities.[215] Utilities implement programs for reduced energy bills for qualifying low-income customers.[216] There are also resources for waste and water bills that leverage federal funds.[217] CARB also coordinated with the CPUC to ensure that the Climate Credit[218] funded from the sale of Cap-and-Trade allowances provided to utilities on behalf of ratepayers is credited equally to households and not based on how much energy is used. These are just a few examples of how the state is designing and implementing programs to avoid increasing existing disparities. The state must continue to find ways to relieve economic burdens on low-income households.

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[214] The number of households in each bracket and the race/ethnicity categories are from American Community Survey 2021 results. Population changes through 2035 and 2045 are not forecast. U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.

[215] CARB. Priority Populations — California Climate Investments. https://www.caclimateinvestments.ca.gov/priority-populations.

[216] CPUC. CARE/FERA Program. https://www.cpuc.ca.gov/lowincomerates/.

[217] California Department of Community Services and Development. Low Income Household Water Assistance Program. https:/www.csd.ca.gov/lihwap.

[218] CPUC. California Climate Credit - FAQ. https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-climate-credit/california-climate-credit---faq.

**Table 3-3: Percentage of households in each race/ethnicity category by household income group**

| Household Income Group ($2021) | Households in Income Group (%) | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | White Not Hispanic | Hispanic | Black Alone | Asian Alone | Native HI or Pacific Islander | American Indian or Alaskan Native | Other | Two or More |
| Less than $50,000 | 26 | 35 | 45 | 25 | 30 | 35 | 37 | 32 |
| $50,000 to $100,000 | 25 | 32 | 27 | 21 | 31 | 33 | 33 | 30 |
| $100,000 to $200,000 | 29 | 25 | 21 | 30 | 30 | 26 | 24 | 27 |
| More than $200,000 | 19 | 7 | 7 | 24 | 9 | 7 | 5 | 11 |

## Natural and Working Lands

The macroeconomic impact of the NWL scenario was evaluated separately in the REMI PI+ model. For the Scoping Plan Scenario, the macroeconomic impact was modeled by assuming that economic activity in the relevant industries grows in proportion to the proposed implementation spending in that industry. All funds for implementing the actions were assumed to be sourced from within the state. For urban forests, the funds were modeled as being sourced from a combination of state government and private property owners in proportion to the current estimated private/public spending ratio. For all other actions, funds were assumed to be sourced from the state government. In each modeled scenario, government spending and income to property owners were reduced relative to the Reference Scenario in proportion to the annual costs of implementation. None of the proposed spending was modeled as being sourced from increased taxes. Additional details on the methodology for evaluating macroeconomic impacts are in Appendix I (NWL Technical Support Document).

While the macroeconomic model does count the increased economic activity in the affected industries as part of GSP, it does not quantify many of the important economic, health, and environmental benefits that would occur if these actions were implemented. While these benefits—like the reduced use of pesticides, value of urban trees, and increased recreational opportunities—would be very significant, they are outside the scope of the macroeconomic model.

The macroeconomic model also makes projections about the total level of employment in the state. The model forecasts that the Scoping Plan Scenario, which greatly increases the level of NWL management actions, channels economic activity toward related industries and would lead to a slight increase in total employment. (Table 3-4). While the model does aim to accurately represent many labor market dynamics, including adjustments of wages and migration rates, it does not account for many costs that might be associated with dramatically scaling up employment in a particular industry, such as the cost of job training.

**Table 3-4: Gross state product and employment relative to a growing California economy for the Scoping Plan Scenario in 2035 / 2045 (NWL)**

| | Scoping Plan Scenario (%) |
|---|---|
| **Gross State Product** | 0.00 / 0.01 |
| **Employment** | 0.12 / 0.10 |
| **Personal Income** | -0.04 / -0.04 |
| **Personal Income per Capita** | -0.04 / -0.14 |

## Health Analysis

Air quality is affected by pollutant emissions from various processes associated with energy systems, including the combustion of fossil fuels, as well as the combustion of vegetation biomass from NWL during wildfires. Pollutants that are important contributors to degraded air quality in California include nitrogen oxides ($NO_x$), particulate matter (PM), reactive organic gases (ROG), and others. Further, in the atmosphere these pollutants are transported away from the locations of the emissions by wind and other phenomena, and undergo chemical reactions that result in the formation of new pollutants such as ground-level ozone and fine particulate matter ($PM_{2.5}$). Both primary (emitted) and secondary (formed) pollutants are important from a public health standpoint and contribute to the incidence of air pollution-related mortality and disease within California populations. Measures focused on GHGs do not incorporate specific targets to reduce emissions of $PM_{2.5}$ or air toxics like benzene. These co-pollutants, which are emitted from many of the same pollution sources as GHGs, affect local air quality and pose known risks to public health, such as the risk of asthma and cardiovascular disease. Generally, for stationary sources, certain harmful pollutants are regulated via local rules and regulations that are reflected in permits for stationary sources and are enforced by local air districts, with CARB also regulating air toxics contaminants from stationary sources with the air districts.

## AB 32 GHG Inventory Sectors

To assess health impacts for the AB 32 GHG Inventory sectors, an integrated modeling approach was used to quantify and value the air pollution-related public health benefits of the Scoping Plan Scenario relative to the Reference Scenario. Additional details about the models, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). Using output from the PATHWAYS model, projections of pollutant emissions to 2045 were developed for stationary, area, and mobile source emissions using a detailed base year CARB pollutant emissions inventory. Further, the emissions are processed, including for where and when they occur in California, using the Sparse Matrix Operator Kernels Emissions (SMOKE) model. For example, on-road vehicle emissions were allocated along existing roadways, and refining emissions were assigned to the locations of existing refineries. It should be noted that the emissions projections represent statewide average reductions associated with high-level assumptions about alternative fuels and technologies. For example, emissions occurring from refineries to produce liquid fuels are reduced in line with petroleum demand. This reduction is applied equally to all refineries in the Scoping Plan Scenario and does not specify individual facility responses to changing demand. Similarly, the Scoping Plan Scenario does not specify which refineries transition to biofuel production or where new electricity generation facilities are built.

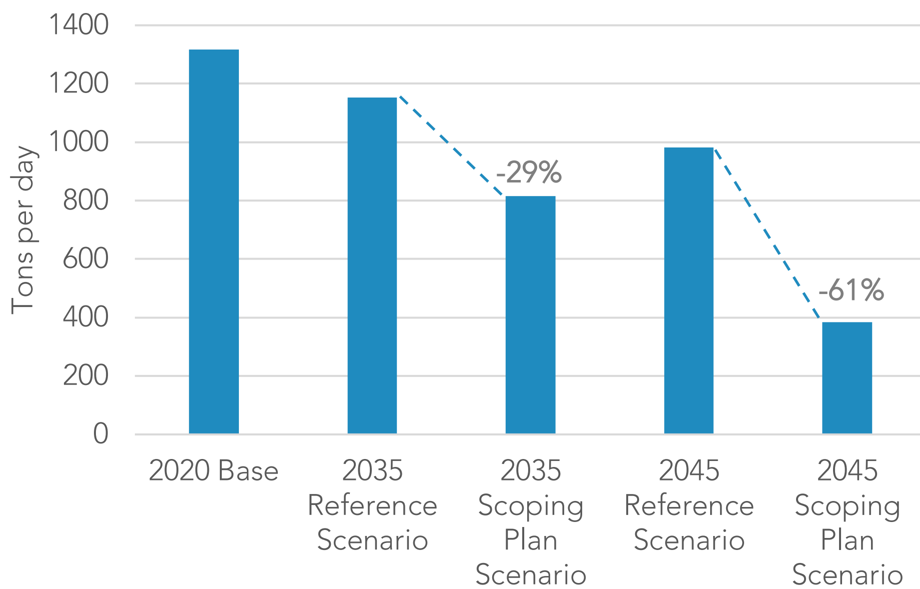
Next, emission changes were translated into impacts on atmospheric pollution levels, including ground-level ozone and $PM_{2.5}$, via an advanced photochemical air quality model called the Community Multiscale Air Quality (CMAQ) model, which accounts for atmospheric chemistry and transport. A comprehensive assessment of how pollutant concentrations are impacted throughout the year was achieved by simulating all months in 2035 and 2045 for the Scoping Plan Scenario.[219] Health benefits were estimated using the U.S. EPA's environmental Benefits Mapping and Analysis Program (BenMAP) model to translate pollutant changes into avoided incidence of mortality, hospital admissions, emergency room visits, and other outcomes as a result of reduced exposure to ozone and $PM_{2.5}$. These outcomes are associated with an economic value in order to aggregate health impacts.

The Scoping Plan Scenario shows a substantial reduction in pollutant emissions relative to the Reference Scenario, including $NO_x$, $PM_{2.5}$, and ROG. Reductions in $NO_x$ are shown in Figure 3-4. Even under a business-as-usual trajectory, emissions are reduced from present levels by 26 percent in 2045 in the Reference Scenario, demonstrating the impact of current regulations and trends in energy sectors. The Scoping Plan Scenario further reduces $NO_x$

[219] This annual approach differs from the episodic modeling approach applied to the Proposed Scenario and Alternatives in the Draft 2022 Scoping Plan Update. Appendix H (AB 32 GHG Inventory Sector Modeling) describes both approaches.

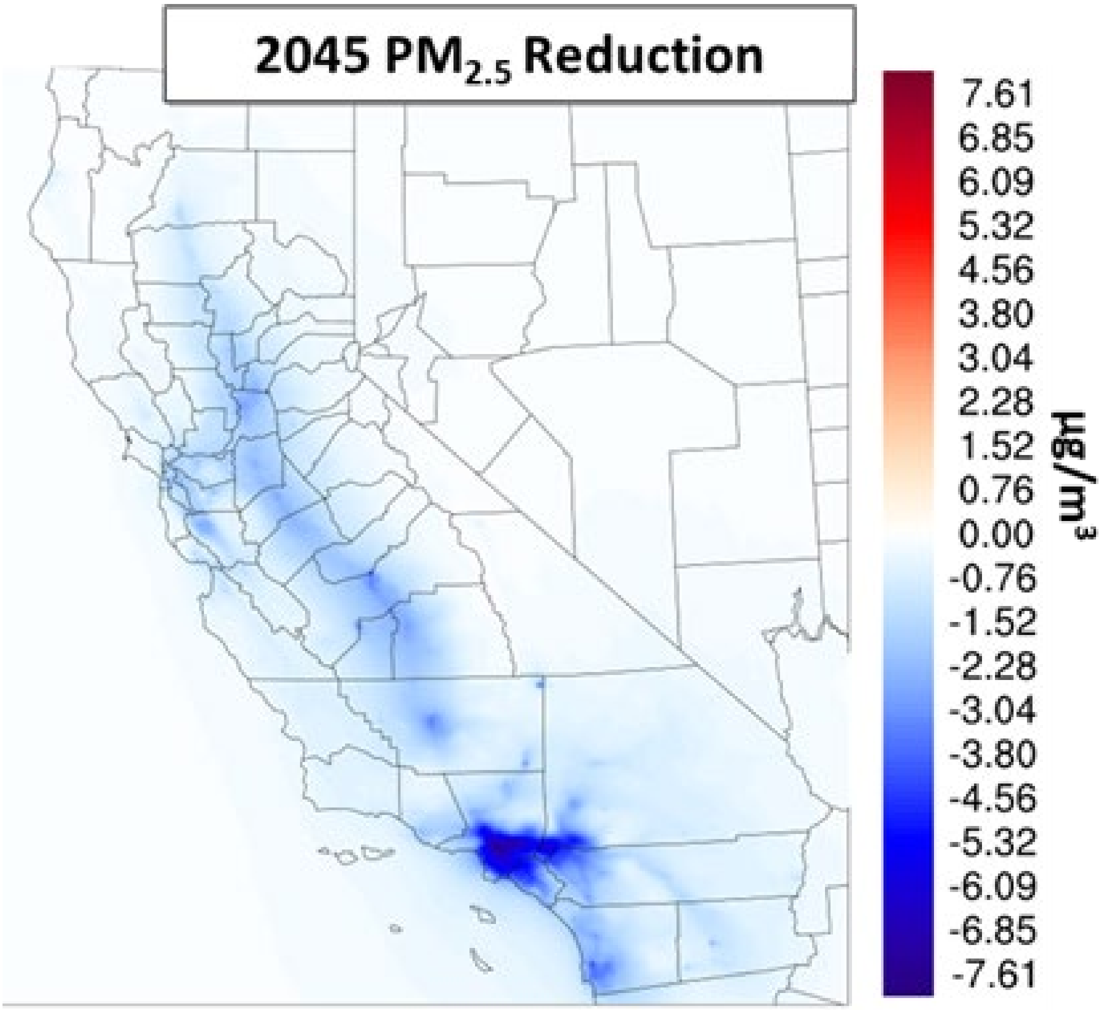
emissions from the Reference Scenario by 29% in 2035 and 61% in 2045. Emission reductions occur throughout the state with particular prominence in urban areas, including the South Coast Air Basin, due to the large presence and activity of emission sources. Appendix H (AB 32 GHG Inventory Sector Modeling) contains additional information about the pollutant emissions modeling and results.

**Figure 3-4: Illustration of NOx emission reductions from current levels for the Reference Scenario and the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**



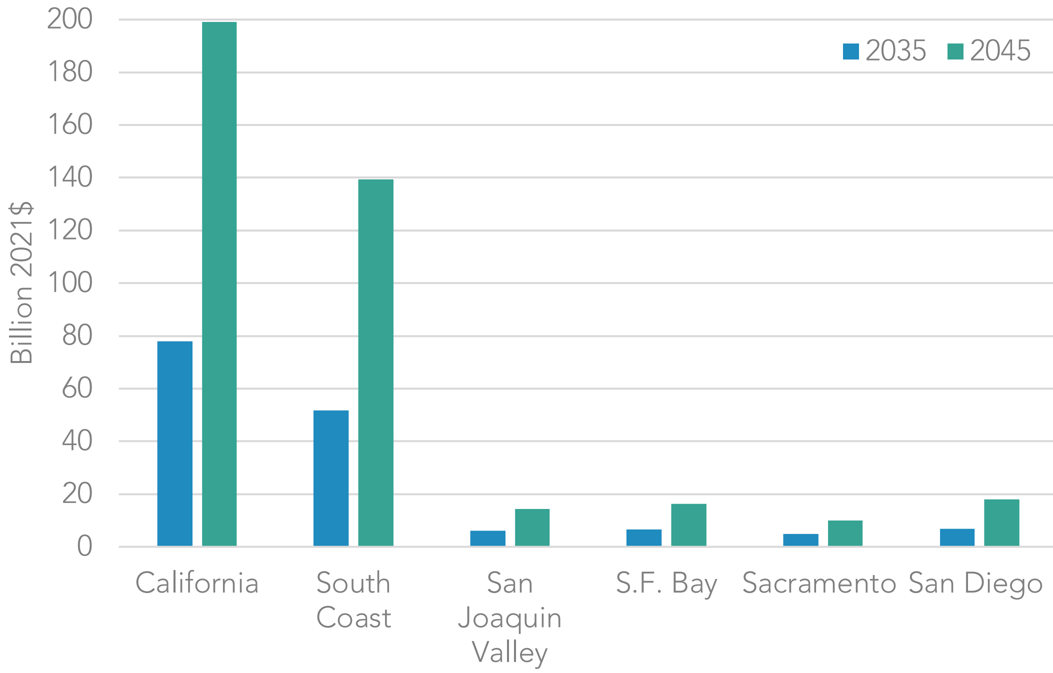

The emission reductions achieve important improvements in air quality throughout California, including reductions in the levels of ozone and $PM_{2.5}$. Reductions in annual $PM_{2.5}$ levels are shown in Figure 3-5. The greatest reductions are evident in Southern California, the San Joaquin Valley, the San Francisco Bay area, and the Greater Sacramento area due to the large presence and activity of emission sources, meteorology, topography, and others. To highlight the extent of the air quality improvements: reductions reach nearly 8 micrograms per cubic meter ($\mu g/m^3$) in 2045 and lead to 76% fewer exceedances of the health-based National Ambient Air Quality $PM_{2.5}$ standard of 12 $\mu g/m^3$. Similarly, ozone improvements reach 19 parts per billion (ppb) and yield 62% fewer exceedance events. Furthermore, the locations of improvements carry important implications for human health as these areas support large urban populations and generally experience the most degraded ozone and $PM_{2.5}$ pollution. Appendix H (AB 32 GHG Inventory Sector Modeling) provides details regarding the atmospheric modeling and results, including differences in ozone and $PM_{2.5}$.

**Figure 3-5: Difference in annual average $PM_{2.5}$ ($\mu g/m^3$) in the Scoping Plan scenario relative to the Reference scenario in 2045 (AB 32 GHG Inventory sectors)**



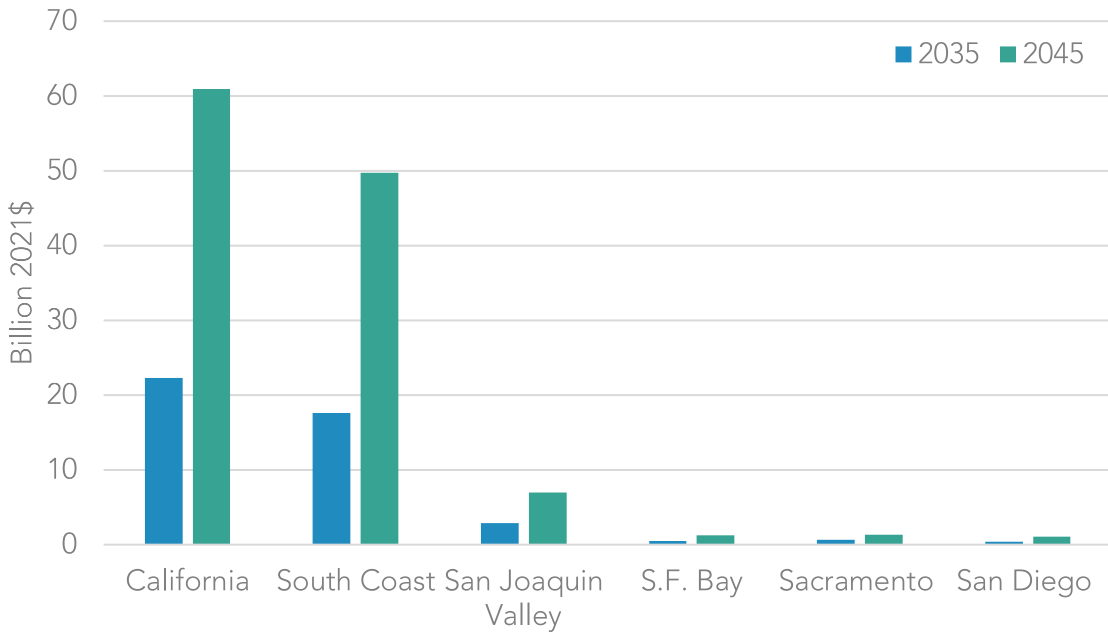

Notable health benefits representing the economic value of the avoided incidence of health effects are associated with the Scoping Plan Scenario. In total, the benefits reach $78 billion in 2035 and $199 billion in 2045, as shown in Figure 3-6. Populations in Southern California benefit the most due to preexisting air quality challenges, significant emission sources and activity, and the presence of a large, dense urban population. Additional details regarding the health impact assessment are provided in Appendix H (AB 32 GHG Inventory Sector Modeling).

**Figure 3-6: Total health benefits estimated from air quality improvements in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**




Furthermore, these benefits accrue within socially and economically disadvantaged communities identified by CalEnviroScreen, where they are most needed. Total health benefits within census tracts identified as disadvantaged communities using CalEnviroScreen 4.0 reach $22 billion in 2035 and $61 billion in 2045, as shown in Figure 3-7. Similarly to the statewide health benefits, the largest share of benefits occurs within disadvantaged communities in Southern California. Additional information on the health benefits within disadvantaged communities can be found in Appendix H (AB 32 GHG Inventory Sector Modeling).

**Figure 3-7: Disadvantaged community health benefits relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**

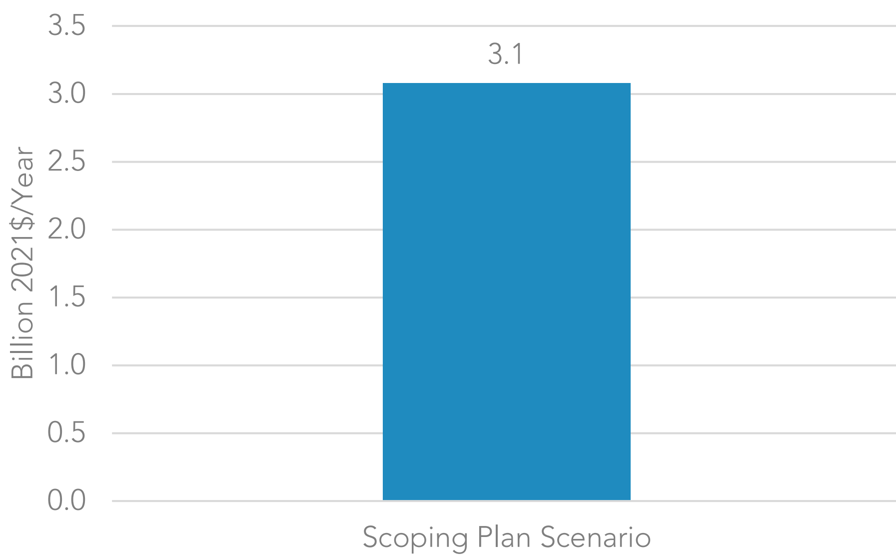



## Natural and Working Lands

For NWL, health benefits were evaluated based on projected $PM_{2.5}$ wildfire emissions on forests, shrublands, and grasslands, discussed in the AB 197 Measure Analysis section of the chapter that follows.[220] The health endpoints for the Scoping Plan Scenario and in Appendix I (NWL Technical Support Document) for the alternative scenarios were the basis for the estimated health benefits shown in Figure 3-8. Health benefits were derived from the preliminary University of California, Los Angeles (UCLA) study that estimated annual health impacts and associated costs from California's wildfires from 2008–2018. Additional details are included in Appendix I (NWL Technical Support Document). These costs were applied to the health endpoints discussed in the AB 197 Measure Analysis section of the chapter.

[220] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. *finalejacrecs.pdf (arb.ca.gov)*.

**Figure 3-8: Total average annual health benefits relative to the Reference Scenario for the Scoping Plan Scenario (NWL)**




As health impacts analyzed here are driven by wildfire emissions, the health benefits for the Scoping Plan Scenario are directly related to the amount of forest, shrubland, and grassland management action. These management actions reduce vegetation fuels and, as a result, wildfire activity. The Scoping Plan Scenario increases the amount of these management actions, reducing wildfire emissions and avoiding incidence of emission-related health effects. The health benefits, or economic value of the avoided incidence of health effects, correspondingly increase with an increasing management implementation rate. Additional details are included in Appendix I (NWL Technical Support Document).

Estimated health benefits do not include the direct impact of wildfires on injuries, deaths, or mental health, nor the indirect costs of lost ecosystem benefits to wildfire. Additional direct health costs may result from wildfire that would likely increase the health benefits from increased forest, shrubland, and grassland management to reduce wildfire activity. Nonetheless, the conservative health benefits under the Scoping Plan Scenario are estimated to be $3.1 billion per year relative to the Reference Scenario for all NWL actions identified in the Scoping Plan Scenario.

## AB 197 Measure Analysis

This section provides estimates for information associated with GHG emissions reduction measures evaluated in this Scoping Plan.[221] These estimates, which were developed as part of the process for meeting the requirements of AB 197 (E. Garcia, Chapter 250, Statutes of 2016), provide information on the relative impacts of the evaluated measures when compared to each other. To support the design of a suite of policies that result in GHG reductions, air quality co-benefits, and cost-effective measures, it is important to understand if a measure will increase or reduce criteria pollutants or toxic air contaminant emissions, or if increasing stringency at additional costs yields few additional GHG reductions. To this end, AB 197 requires the following for each potential emissions reduction measure evaluated in any Scoping Plan update:

- The range of projected GHG emissions reductions that result from the measure;
- The range of projected criteria pollutant emission reductions that result from the measure; and
- The cost-effectiveness, including avoided social costs, of the measure.

The following sections describe the evaluation of measures for the AB 32 GHG Inventory sectors and NWL. For the purposes of this Scoping Plan, the identified emissions reduction measures for the analysis required by AB 197 are actions grouped by sectors where several policies and programs are expected to overlap. This approach reflects the most granular feasible analysis given the modeling tools available,[222] the overlap and interaction effects among policies and incentive programs, the longer planning horizon used for this Scoping Plan compared to previous efforts, and the scale of transition needed to achieve carbon neutrality. To implement this Scoping Plan, dozens of individual regulations, policies, and incentive programs are anticipated that work together to drive down emissions across all economic sectors and support actions. Every specific policy or incentive program that could contribute to the deployment of clean technology and energy called for in this plan may overlap in ways that make it infeasible to tease out those policies and programs' individual effects with any reasonable degree of certainty. For example, in the transportation sector, deploying ZEVs and reducing driving demand may be achieved through a combination of the implementation of new or existing regulations, fuels programs, incentive programs, and VMT reduction initiatives that can each contribute to reductions in emissions for the sector. It is not feasible to isolate each sub action from each other at this time in terms of the share of contribution to total reductions. The estimated emission

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[221] AB 197 calls for the evaluation of "emission reduction measures." This Scoping Plan treats each action and its variants on stringency as emission reduction measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative.
[222] See Appendix H (AB 32 GHG Inventory Sector Modeling and Appendix I (NWL Technical Support Document).

reductions, health endpoints, and costs by measure for the Scoping Plan Scenario are presented in this chapter, and the corresponding estimates for the Proposed Scenario and Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

Because many of the measures and underlying assumptions interact with each other, isolating the GHG emission reductions, corresponding changes to fuel combustion, and associated cost of an individual measure is analytically challenging. Each measure is evaluated by examining the change in fuel combustion, cost, and emissions associated with just that measure using the PATHWAYS model. The difference between the Scoping Plan Scenario and the Reference Scenario is estimated for each measure. Starting from the Scoping Plan Scenario, the modeling assumptions for an individual measure are reverted to the Reference Scenario values, resulting in GHG reductions, changes to fuel combustion, and costs (or savings). This approach does not reflect interactions between sectors in PATHWAYS that influence the results for each complete alternative, presented earlier. As such, the values associated with each measure should not be added to obtain an overall scenario estimate.

To arrive at the 2045 target for NWL, CARB modeled the ecological impact that climate smart land-based management strategies (suites of on-the-ground actions, or *treatments,* that are used across the landscape to manipulate an ecosystem) will have on ecosystem carbon; and whenever possible, additional co-benefits from those actions. The Scoping Plan Scenario incorporates a set of land management actions at varying scales of implementation for each land type to achieve the GHG emission reductions. Each land type, and its associated management actions, was considered a measure for this analysis. For modeling individual landscapes and management actions, CARB used a suite of models. The complexity of these models varies by land type, depending on the existing science, data, and availability of existing models to use. Appendix I (NWL Technical Support Document) provides detailed modeling assumptions for each NWL type. The estimated emission reductions, health endpoints, and costs by measure under the Scoping Plan Scenario for each NWL type are presented in this chapter, and the corresponding estimates for the Proposed Scenario and NWL Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

## Estimated Emissions Reductions

Both GHG emissions reductions and emissions of criteria air pollutants were evaluated for the AB 32 GHG Inventory sectors and for NWL. The methods and results are described in this section.

### AB 32 GHG Inventory Sectors

In the absence of having direct modeling results for criteria pollutant estimates from PATHWAYS, CARB estimated criteria pollutant emissions impacts by using changes in fuel combustion in units of exajoules from PATHWAYS and emission factors in units of tons per exajoule to estimate the change in emissions in tons per year. Emission factors from a variety of sources for each sector were utilized, including but not limited to CARB's mobile source emissions models,[223] U.S. EPA's AP 42 Emissions Factors,[224] and the South Coast Air Quality Management District's (AQMD's) District Rules.[225] These emission factors were applied to fuel burn change by fuel type, sector, equipment type, and process, where applicable. Statewide annual average emissions were estimated for three criteria pollutants: $NO_x$, $PM_{2.5}$, and ROG.

Table 3-5 provides the estimated GHG and criteria pollutant emission reductions for the measures in the Scoping Plan Scenario in 2035 and 2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Based on the estimates below, these measures are expected to provide air quality benefits. The estimates provided in this chapter and Appendix C (AB 197 Measure Analysis) are appropriate for comparing across alternatives considered for the development of this Scoping Plan, but they are not precise estimates.

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[223] CARB. MSEI - Modeling Tools. *https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-modeling-tools*.
[224] U.S EPA. AP-42: Compilation of Air Emissions Factors. *https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors*.
[225] South Coast AQMD. South Coast AQMD Rule Book. *https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book*.

**Table 3-5: Estimated GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario in 2035/2045 (AB 32 GHG Inventory sectors)**

| Measure | GHG Reductions ($MMTCO_2$) | NOx Reductions (Short Tons/Year) | $PM_{2.5}$ Reductions (Short Tons/ Year) | ROG Reductions (Short Tons/Year) |
|---|---|---|---|---|
| **Deploy ZEVs and reduce driving demand** | -46 / -84 | -51,620 / -122,806 | -2,008 / -6,506 | -18,967 / -30,410 |
| **Coordinate supply of liquid fossil fuels with declining California fuel demand** | -25 / -30 | -1,601 / -2,707 | -978 / -1,705 | -747 / -1,323 |
| **Generate clean electricity** | -8 / -31 | -92 / -1,555 | -177 / -1,382 | -41 / -425 |
| **Decarbonize industrial energy supply** | -9 / -22 | -21,172 / -34,876 | -1,188 / -2,527 | -3,710 / -6,298 |
| **Decarbonize buildings** | -14 / -35 | -8,105 / -94,455 | -826 / -6,877 | -1,093 / -8,109 |
| **Reduce non-combustion emissions**[a] | -0.41 / -0.52 ($MMTCH_4$) | N/A | N/A | N/A |
| **Compensate for remaining emissions** | -25 / -64 | N/A | N/A | N/A |

[a] Methane emissions reductions are reported for this measure.

The measures related to reducing non-combustion emissions and compensating for the remaining emissions do not include changes to fuel combustion, and therefore are not associated with changes to air pollutants. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

## Natural and Working Lands

NWL ecosystems naturally vary between being a source and a sink for carbon over time. The NWL ecosystem carbon stock changes projected through mid-century by the suite of models were used to estimate net emissions or emissions reductions relative to the Reference Scenario. These changes in carbon stocks were affected by projected climate change, the implementation of management actions under the various scenarios, land conversion, and (for forests, shrublands, grasslands) wildfire. Each NWL type was evaluated, and an overview of all NWL is presented in Table 3-6. More detailed results for each NWL type can be found in Appendix C (AB 197 Measure Analysis).

**Table 3-6: Estimated average annual GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario from 2025–2045 (NWL)**

| Measure | GHG Reductions ($MMTCO_2e$/year) | $PM_{2.5}$ Reductions (MT/Year) |
|---|---|---|
| **Forests/Shrublands/Grasslands** | -0.12 | -17,500 |
| **Annual Croplands** | -0.25 | N/A |
| **Perennial Croplands** | -0.01 | N/A |
| **Urban Forest** | -1.29 | N/A |
| **Wildland Urban Interface (WUI)** | 0.75 | N/A |
| **Wetlands** | -0.43 | N/A |
| **Sparsely Vegetated Lands** | <-0.01 | N/A |

Fine particulate wildfire emissions were evaluated for forests, shrublands, and grasslands only. Wildfire emissions decreased under the Scoping Plan Scenario compared to the Reference Scenario. The Scoping Plan Scenario's higher level of management actions that reduce tree or shrub densities, protect large trees, reintroduce fire to the landscape, and diversify species and structures result in greater reductions in wildfire emissions.

## Estimated Health Endpoints

Climate change mitigation will result in both environmental and health benefits. This section provides information about the potential health benefits of the Scoping Plan Scenario. Health benefits are primarily the result of reduced $PM_{2.5}$ pollution, both from stationary and mobile sources, as well as wildfire in forests, shrublands, and chaparral.

### AB 32 GHG Inventory Sectors

CARB used the criteria pollutant emissions in Table 3-5 to understand potential health impacts. Similar to the air quality estimates, this information should be used to understand the relative health benefits of the various measures and should not be taken as absolute estimates of health outcomes. CARB used the incidence-per-ton (IPT) methodology to quantify the health benefits of emission reductions. The IPT methodology is based on a methodology developed by the U.S.

EPA.[226,227,228,229] Under the IPT methodology, changes in emissions are approximately proportional to the resulting changes in health outcomes. IPT factors are derived by calculating the number of health outcomes associated with exposure to $PM_{2.5}$ for a baseline scenario using measured ambient concentrations and dividing that number by the emissions of $PM_{2.5}$ or a precursor. To estimate the reduction in health outcomes, the emission reductions are multiplied by the IPT factor. For future years, the number of outcomes is adjusted to account for population growth. IPT factors were computed for the two types of $PM_{2.5}$: primary $PM_{2.5}$ and secondary $PM_{2.5}$ of ammonium nitrate aerosol formed from precursors.

For this AB 197 analysis, CARB calculated the health benefits associated with the five key measures that are represented by changes to fuel combustion. The health benefits associated with emission reductions for the Scoping Plan Scenario were estimated for each air basin and then aggregated for the entire state of California. CARB assumed that the statewide emission reductions distribution among the air basins is proportional to the baseline emissions in that air basin.

Calculated health endpoints include premature mortality, cardiovascular emergency department (ED) visits, acute myocardial infarction, respiratory ED visits, lung cancer incidence, asthma onset, asthma symptoms, work loss days, hospitalizations due to cardiopulmonary illnesses, hospitalizations due to respiratory illnesses, hospital admissions for Alzheimer's disease, and hospital admissions for Parkinson's disease.[230,231,232] These health endpoints were calculated using the IPT method for estimated emission reductions. Table 3-7 compares the health benefits of emission reductions associated with each measure for the Scoping Plan Scenario in the year

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[226] CARB. CARB's Methodology for Estimating the Health Effects of Air Pollution. Retrieved February 9, 2021. https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution.
[227] Fann, N., C. M. Fulcher, and B. J. Hubbell. 2019. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." *Air Quality, Atmosphere & Health* 2:169–176. https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/.
[228] Fann, N., K. R. Baker, and C. M. Fulcher. 2012. "Characterizing the $PM_{2.5}$-related health benefits of emission reductions for 17 industrial, area and mobile emission sectors across the U.S." *Environ Int*. 49:141–51. November 15. https://www.sciencedirect.com/science/article/pii/S0160412012001985.
[229] Fann, N., K. Baker, E. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. "Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025." *Environ. Sci. Technol.* 52 (15), 8095–8103. https://pubs.acs.org/doi/abs/10.1021/acs.est.8b02050.
[230] CARB. CARB's Methodology. https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution.
[231] CARB. 2022. Updated Health Endpoints in CARB's Health Benefits Methodology. Evaluating New Health Endpoints for Use in CARB's Health Analyses.
[232] Cardio-pulmonary mortality, hospitalizations due to cardiopulmonary illnesses, and hospital admissions due to respiratory illnesses endpoints utilize studies documented in CARB's methodology document. For future assessments, CARB will use more recent studies to estimate cardiovascular hospital admissions and respiratory hospital admissions, as documented in CARB's updated health endpoints memo.

specified (2035 or 2045). The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

**Table 3-7: Estimated avoided incidence of mortality, cardiovascular and respiratory disease onset, work loss days and hospital admissions relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**

| Measure | Mortality | Cardiovascular ED Visits | Acute Myocardial Infarction | Respiratory ED Visits | Lung Cancer Incidence | Asthma Onset | Asthma Symptoms | Work Loss Days | Hospital Admissions, Cardiovascular | Hospital Admissions, Respiratory | Hospital Admissions, Alzheimer's Disease | Hospital Admissions, Parkinson's Disease |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Deploy ZEVs and reduce driving demand in 2035** | 635 | 170 | 70 | 400 | 45 | 1,475 | 128,930 | 92,510 | 95 | 115 | 245 | 40 |
| **Deploy ZEVs and reduce driving demand in 2045** | 1,820 | 475 | 200 | 1,115 | 135 | 3,995 | 343,095 | 255,800 | 295 | 350 | 745 | 125 |
| **Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2035** | 115 | 30 | 15 | 70 | 10 | 275 | 23,530 | 16,880 | 20 | 20 | 50 | 10 |

| Measure | Mortality | Cardiovascular ED Visits | Acute Myocardial Infarction | Respiratory ED Visits | Lung Cancer Incidence | Asthma Onset | Asthma Symptoms | Work Loss Days | Hospital Admissions, Cardiovascular | Hospital Admissions, Respiratory | Hospital Admissions, Alzheimer's Disease | Hospital Admissions, Parkinson's Disease |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2045** | 215 | 55 | 25 | 130 | 15 | 490 | 40,860 | 30,445 | 35 | 40 | 95 | 15 |
| **Generate clean electricity in 2035** | 20 | 5 | 0 | 10 | 0 | 45 | 3,930 | 2,820 | 5 | 5 | 10 | 0 |
| **Generate clean electricity in 2045** | 170 | 45 | 20 | 105 | 15 | 385 | 32,065 | 23,890 | 25 | 30 | 75 | 10 |
| **Decarbonize industrial energy supply in 2035** | 300 | 80 | 35 | 190 | 20 | 695 | 60,660 | 43,520 | 45 | 55 | 115 | 20 |
| **Decarbonize industrial energy supply in 2045** | 595 | 155 | 65 | 365 | 45 | 1,310 | 111,925 | 83,435 | 95 | 115 | 245 | 40 |

| Measure | Mortality | Cardiovascular ED Visits | Acute Myocardial Infarction | Respiratory ED Visits | Lung Cancer Incidence | Asthma Onset | Asthma Symptoms | Work Loss Days | Hospital Admissions, Cardiovascular | Hospital Admissions, Respiratory | Hospital Admissions, Alzheimer's Disease | Hospital Admissions, Parkinson's Disease |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Decarbonize buildings in 2035** | 155 | 40 | 15 | 95 | 10 | 360 | 31,130 | 22,335 | 25 | 30 | 60 | 10 |
| **Decarbonize buildings in 2045** | 1,610 | 420 | 175 | 985 | 120 | 3,550 | 303,830 | 226,500 | 260 | 310 | 665 | 115 |
| Note: All values are rounded to the nearest 0 or 5. | | | | | | | | | | | | |

The measures related to reducing non-combustion emissions and compensating for remaining emissions do not include changes to fuel combustion and therefore are not associated with changes to air pollutants or health endpoints. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

Although the estimated health outcomes presented are based on a well-established methodology, they are subject to uncertainty. For instance, future population estimates are subject to increasing uncertainty as they are projected further into the future, and baseline incidence rates can experience year-to-year variation. Also, the relationship between changes in pollutant concentrations and changes in pollutant or precursor emissions is assumed to be approximately proportional.

In addition, emissions are reported at an air basin level and do not capture local variations. These estimates also do not account for impacts from global climate change, such as temperature rise, and are only based on the scenarios in this Scoping Plan.

The fuel changes for each AB 197 measure are estimated based on the impact of each measure compared to the Reference Scenario for the years 2035 and 2045. Therefore, aggregating the effect of each measure would overestimate the impacts of the Scoping Plan Scenario because the implementation of each measure would affect the level of benefits of the other measures. This measure-by-measure analysis uses a different methodology for calculating health endpoints than does the health analysis for the complete Scoping Plan Scenario provided earlier.

## Natural and Working Lands

Implementation of NWL management strategies to mitigate and adapt to climate change will result in both environmental and health benefits. This section provides information about the potential health benefits of measures evaluated for the Scoping Plan Scenario. For this analysis, health benefit estimates were focused on increases or decreases to $PM_{2.5}$ resulting from wildfire emissions on forests, shrublands, and grasslands.[233] Other health benefits resulting from NWL management actions in the Scoping Plan Scenario are not quantified here but are important for all Californians. This includes, but is not limited to, reductions in exposure to synthetic pesticides when switching to organic agricultural systems, improvements in shade availability and mental health with increasing urban forest cover, improved mental health from opportunities for recreation in resilient and healthy environments, and protection from floods and rising sea levels.

[233] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. finalejacrecs.pdf (arb.ca.gov).

These examples are by no means exhaustive, as our natural and working lands provide immense health benefits to everyone.

For this analysis, CARB used the $PM_{2.5}$ emissions in Table 3-6 to understand potential health impacts. This information should be used to understand the relative health endpoints of the various measures and should not be taken as absolute estimates of health outcomes of this Scoping Plan statewide or within a specific community. The IPT methodology was used to calculate health endpoints, similar to the AB 32 GHG Inventory Sector analysis. CARB calculated the annual health endpoints associated with the wildfire emissions changes resulting from the implementation of management strategies on forests, shrublands, and grasslands under each alternative. The annual health endpoints associated with emission reductions for the Scoping Plan Scenario were estimated for the entire state. Calculated health endpoints include emissions-caused mortality, hospital admittance, and emergency room visits from asthma; hospital admittance from chronic obstructive pulmonary disease; and emergency room visits from respiratory and cardiovascular outcomes. Table 3-8 compares the average annual health endpoints of wildfire emission reductions associated with the Scoping Plan Scenario over the period 2025–2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

**Table 3-8: Estimated average annual avoided incidence of hospital admissions, emergency room visits, and mortality relative to the Reference Scenario for the Scoping Plan Scenario resulting from forest, shrubland, and grassland wildfire emissions (NWL)**

| Health Endpoints from Forest, Shrubland, and Grassland Wildfire Emissions | Average Annual Avoided Incidence |
|---|---|
| Hospital admissions from asthma | 22 |
| Hospital admissions from chronic obstructive pulmonary disease without asthma | 19 |
| Hospital admissions from all respiratory outcomes | 63 |
| Emergency room visits from asthma | 155 |
| Emergency room visits from all respiratory outcomes | 419 |
| Emergency room visits from all cardiovascular outcomes | 156 |
| All causes of mortality | 394 |

## Estimated Social Cost

*Social costs* are generally defined as the cost of an action on people, the environment, or society and are widely used to understand the impact of regulatory actions. One tool, the social cost of greenhouse gases (SC-GHG), is an estimate of the present value of the costs associated with the emission of GHGs in future years. It combines climate science and economics to help understand the benefits of reducing GHG emissions. The estimates of the social cost of carbon (SC-$CO_2$) and social cost of methane (SC-$CH_4$), two types of SC-GHGs presented here, estimate the value of the net harm to society associated with adding GHGs to the atmosphere in a given year; they do not represent the cost of actions taken to reduce GHG emissions (known as the *cost of abatement*) nor the cost of GHG emissions reductions. In principle, the SC-GHG includes the value of climate change impacts, including but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and other natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. It reflects the societal value of reducing emissions of the gas in question by one metric ton.[234] Many of these damages from GHG emissions today will affect economic outcomes throughout the next several centuries.

In 2008, federal agencies began incorporating SC-$CO_2$ estimates into the analysis of their regulatory actions. U.S. EPA has used various models and discount rates to determine the value of future impacts. Generally, these models begin with assumptions to predict economic activity over time, along with projected GHG emissions. The modeled emissions are input into a model of the global climate system, which then translates into estimates of surface temperature, sea level rise, and other impacts. These outputs are used to estimate economic damages per ton of GHG emitted in a given year in the future. Since the models are calculating the present value of future damages, a discount rate is applied. For example, the SC-$CO_2$ for the year 2045 represents the value of climate change damages from a release of $CO_2$ in 2045 discounted back to today. The present value is significantly affected by the discount rate used; a higher discount rate results in a lower present value. For example, in 2021 dollars the SC-$CO_2$ in 2045 is $31 using a 5 percent discount rate, $88 using a 3 percent discount rate, and $122 using a 2.5 percent discount rate. Additional detail is included in Appendix C (AB 197 Measure Analysis).

The 2017 Scoping Plan utilized SC-$CO_2$ and SC-$CH_4$ Obama Administration-era values developed by the Council of Economic Advisors and the Office of Management and Budget-convened Interagency Working Group on the Social Cost of Greenhouse Gases (IWG)[235] to consider the social costs of actions to reduce GHG emissions. The Biden Administration reinstated these values in February 2021,[236] after they had been rescinded and significantly revised by the Trump Administration. The reinstatement was considered an interim step, and the Biden Administration also reconvened the IWG to continue its work to evaluate and incorporate the latest climate science and economic research and

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[234] U.S. Government. Interagency Working Group on Social Cost of Greenhouse Gases. February 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[235] Originally titled the “Interagency Working Group on the Social Cost of Carbon,” the IWG was renamed in 2016. 82 Fed. Reg. 16093, 16095-96 (Mar. 28, 2017). https://www.govinfo.gov/content/pkg/FR-2017-03-31/pdf/2017-06576.pdf.

[236] Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, Executive Order 13990 (Jan. 20, 2021), 86 Fed. Reg. 7037 (Jan. 25, 2021). https://www.energy.gov/sites/default/files/2021/02/f83/eo-13990-protecting-public-health-environment-restoring.pdf. IWG, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990 (February 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf See also, The White House. 2021. A Return to Science: Evidence-Based Estimates of the Benefits of Reducing Climate Pollution. https://www.whitehouse.gov/cea/written-materials/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.

respond to the National Academies' recommendations from 2017 as it develops a more complete revision of the estimates.

It is important to note that the models used to produce SC-GHG estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate literature. There are additional costs to society, including the costs associated with changes in co-pollutants and costs that cannot be included due to modeling and data limitations. The IWG has stated that the range of the interim SC-GHG estimates likely underestimates societal damages from GHG emissions.[237] The revised estimates were originally slated to be released in early 2022 but were stalled.[238] CARB staff is applying the interim values presented in the IWG February 2021 Technical Support Document (TSD), which reflect the best available science in the estimation of the socioeconomic impacts of GHGs.[239] This Scoping Plan utilizes the TSD standardized range of discount rates, from 2.5 to 5 percent, to represent varying valuation of future damages.

## AB 32 GHG Inventory Sectors

Table 3-9 presents the estimated social cost, in terms of avoided economic damages, for each measure of the Scoping Plan Scenario. For each measure, Table 3-9 includes the range of the SC-$CO_2$ and SC-$CH_4$ that results from the GHG emissions reductions in 2035 and 2045 at 2.5 and 5 percent discount rates. Additional background on the SC-GHG and methodology for calculating the SC-$CO_2$ and SC-$CH_4$ estimates in this Scoping Plan, as well as estimates for the alternatives, are provided in Appendix C (AB 197 Measure Analysis).

[237] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[238] See *Louisiana v. Biden* (W.D. La. 2022) 585 F.Supp.3d 840, stayed pending review (5th Cir. Mar. 16, 2022) 2022 WL 866282. A federal district court ruling issued in early February 2022 had granted a preliminary injunction blocking the Biden Administration from using the interim IWG SC-GHG estimates. However, a federal appeals court overturned the lower court's preliminary injunction in March 2022, which allows the Biden Administration to continue using the policy as legal proceedings continue. CARB will continue to monitor the litigation. However, the federal action does not prohibit CARB from using social cost of carbon and CARB will use the best available science regardless of politics. A separate federal appeals court upheld the Biden administration's use of the IWG SC-GHG estimates in October 2022. *Missouri v. Biden* (8th Cir. 2022) ____ F.4th ____.

[239] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

**Table 3-9: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**

| Measure | Social Cost of Carbon in 2035, 5%–2.5% Discount Rate<br><br>Billion USD (2021 dollars) | Social Cost of Carbon in 2045, 5%–2.5% Discount Rate<br><br>Billion USD (2021 dollars) |
|---|---|---|
| **Deploy ZEVs and reduce driving demand** | 1.12–4.87 | 2.64–10.23 |
| **Coordinate supply of liquid fossil fuels with declining California fuel demand** | 0.61–2.63 | 0.95–3.67 |
| **Generate clean electricity** | 0.20-0.88 | 0.97–3.75 |
| **Decarbonize industrial energy supply** | 0.23–1.01 | 0.69–2.67 |
| **Decarbonize buildings** | 0.35–1.52 | 1.11–4.32 |
| **Reduce non-combustion emissions** | 0.51–1.29 (SC-$CH_4$) | 0.86–2.01 (SC-$CH_4$) |
| **Compensate for remaining emissions** | 0.61–2.66 | 2.03–7.84 |
| **Scoping Plan Scenario SC-$CO_2$**<br>**Scoping Plan Scenario SC-$CH_4$**<br>**Scoping Plan Scenario (Total)[a]** | 2.4–10.4<br>0.51–1.3<br>2.9–11.7 | 5.6–21.9<br>0.86–2.0<br>6.5–23.9 |

[a] CARB staff could not precisely separate some $CO_2$ and $CH_4$ from other GHGs from PATHWAYS outputs, but the contribution is believed to be small for purposes of calculating the social cost of carbon. The approach used to estimate GHG emissions reductions for individual measures in PATHWAYS does not reflect cross-sector interactions. Therefore, the GHG values for each measure do not sum to the overall scenario total. The total GHG emissions reduction used in this calculation is 97 $MMTCO_2e$ in 2035 and 180 $MMTCO_2e$ in 2045.

## Natural and Working Lands

The SC-$CO_2$ estimates for the NWL measures shown in Table 3-10, in terms of avoided economic damages, reflect 2021 IWG interim values, updated for inflation, similar to the AB 32 GHG Inventory Sector analysis. This analysis utilizes the 2.5 percent and 5 percent discount rate and the average annual emissions reductions from each NWL type from 2025–2045. Estimates for all alternatives are included in Appendix C (AB 197 Measure Analysis).

**Table 3-10: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (NWL)**

| Measure | Social Cost of Carbon in 2035, 5%–2.5% Discount Rate<br><br>Billion USD (2021 dollars) | Social Cost of Carbon in 2045, 5%–2.5% Discount Rate<br><br>Billion USD (2021 dollars) |
|---|---|---|
| **Forests/Shrublands/Grasslands** | 0.003–0.012 | 0.004–0.014 |
| **Annual Croplands** | 0.006–0.027 | 0.008–0.031 |
| **Perennial Croplands** | <0.001–0.001 | 0.000–0.001 |
| **Urban Forest** | 0.032–0.138 | 0.041–0.157 |
| **Wildland Urban Interface (WUI)** | (0.018) – (0.080)[a] | (0.023) – (0.090) |
| **Wetlands** | 0.011–0.046 | 0.014–0.053 |
| **Sparsely Vegetated Lands** | <0.001 | <0.001 |

[a] Parentheses indicate an increase in estimated social cost, i.e., an increase in economic damages. This is only the case for WUI measures where emissions are increased, shown in Table 3-6. The estimated social cost does not account for the decrease in wildfire risk or decrease in wildfire damages resulting from the WUI measures.

## Social Costs of GHGs in Relation to Cost-Effectiveness

AB 32 includes a requirement that rules and regulations "achieve the maximum technologically feasible and cost-effective" greenhouse gas emissions reductions.[240] Under AB 32, *cost-effectiveness* means the relative cost per metric ton of various GHG reduction strategies,[241] which is the traditional cost metric associated with emission control. In contrast, the SC-$CO_2$, SC-$CH_4$, and social cost of nitrous oxide (SC-$N_2O$), because they are estimates of the cost to society of additional GHG emissions, can be used to estimate of the economic benefits of reducing emissions, but do not take into account the cost of the actions that must be taken to achieve those GHG emissions reductions.

There may be technologies or policies that do not appear to be cost-effective when compared to the SC-$CO_2$, SC-$CH_4$, and SC-$N_2O$ associated with GHG reductions. However, these technologies or policies may result in other benefits that are not reflected in the IWG social costs. Examples include the evaluation of social diversification of the portfolio of transportation fuels (a goal outlined in the Low Carbon Fuel Standard) and reductions in criteria pollutant emissions from power plants (as in the Renewables Portfolio Standard). Additionally, costs for new technology may be higher early on in a technology's development cycle and may drop over time as use of the technology is scaled up.

## Estimated Cost per Metric Ton

AB 197 requires an estimation of the cost-effectiveness of the measures evaluated for this Scoping Plan. The cost (or savings)[242] per metric ton of $CO_2e$ reduced for each measure is one metric for comparing the performance of the measures. Additional factors beyond the cost per metric ton that could be considered include continuity with existing laws and policies, implementation feasibility, contribution to fuel diversity and technology transformation goals, and health and other benefits to California. These considerations are not reflected in the cost per metric ton estimates presented below. It is important to understand the relative cost-effectiveness of individual measures as presented in this section. However, the economic analysis presented earlier in this chapter, in Appendix H

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[240] AB 32 Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.
[241] Health & Saf. Code § 38505(d).
[242] Similarly, to the direct costs reported earlier, the cost per metric ton of a measure reflects the stock costs and any fuel or efficiency savings associated with a measure divided by the GHG emission reduction achieved by the measure. Costs are reported as positive values, and savings are reported as negative values.

(AB 32 GHG Inventory Sector Modeling), and in Appendix I (NWL Technical Support Document) provides a more comprehensive analysis of how the Scoping Plan Scenario and alternative scenarios affect the state's economy and jobs.

## AB 32 GHG Inventory Sectors

The cost per metric ton for the AB 32 GHG Inventory sectors was computed for each measure independently relative to the Reference Scenario using the sensitivity calculations based on PATHWAYS and RESOLVE outputs. The difference in the annualized cost between the Scoping Plan Scenario and the Reference Scenario was computed for each measure in 2035 and in 2045. The incremental cost was divided by the incremental GHG emissions impact to calculate the cost per metric ton in each year. To capture the fuel and GHG impacts of investments made from 2022 through 2035, or from 2022 through 2045, CARB computed an average annual cost per metric ton. The incremental cost in each year was averaged over the period. This value is divided by the corresponding annual, incremental GHG impact averaged over the same period.

The cost metric includes the annualized incremental cost of energy infrastructure, such as zero-emission vehicles, electric appliances, and required revenue to support all electric assets. A residual value for equipment such as vehicles or appliances that are retired early is included. The annual fuel cost or avoided fuel cost that results from efficiency improvements or changes to demand for fuels associated with transitioning to alternative fuels is included. Not included in this cost metric are costs that represent transfers within the state, such as incentive payments for early retirement of equipment.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, the values do not capture fuel savings or GHG reductions associated with the full economic lifetime of measures that have been implemented by the target date of 2035 or 2045 but whose impacts extend beyond the target date.

Table 3-11 includes the cost per metric ton and annual average cost per metric ton estimates for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Measures that are relatively less costly in 2035 or 2045 are also less costly over the extended period. As noted earlier, incremental costs of new vehicles are generally offset by gains in efficiency and avoided fuel consumption resulting in negative cost per metric ton.

**Table 3-11: Estimated cost per metric ton of reduced $CO_2e$ relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)**

| Measure | Annual Cost, 2035 ($/ton) | Average Annual Cost, 2022–2035 ($/ton) | Annual Cost, 2045 ($/ton) | Average Annual Cost, 2022–2045 ($/ton) |
|---|---|---|---|---|
| **Deploy ZEVs and reduce driving demand** | -171 | -99 | -103 | -122 |
| **Coordinate supply of liquid fossil fuels with declining CA fuel demand** | 60 | 109 | -50 | 39 |
| **Generate clean electricity**[a] | 101 | 156 | 145 | 161 |
| **Decarbonize industrial energy supply** | 290 | 217 | 257 | 274 |
| **Decarbonize buildings** | 235 | 230 | 112 | 213 |
| **Reduce non-combustion emissions** | 93 | 94 | 106 | 99 |
| **Compensate for remaining emissions** | 745 | 823 | 236 | 485 |

[a] Note: The denominator of this calculation (2045) does not include GHG reductions occurring outside of California resulting from SB 100. If these reductions were included, this number would be lower.

## Natural and Working Lands

The cost per metric ton for NWL measures were computed for the Scoping Plan Scenario relative to the Reference Scenario using the projected carbon stock/sequestration data from the NWL modeling and the direct cost estimates for each management action, described earlier. Direct costs represent the cost of implementing a certain management action. The projected emissions reductions take into account the loss of carbon that results from the management action, such as fuels reduction treatments in forests, as well as climate change effects on growth. The direct cost for each NWL measure was divided by the average annual emission reductions presented in Table 3-6 to produce the cost per metric ton. The increasing effect of climate change on diminished future growth reduces the ability of the land to sequester or store carbon, driving up the cost per ton.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, emissions benefits of NWL management actions often take longer time periods to accrue, and these values only capture GHG reductions up to 2045.

Table 3-12 includes the average cost per metric ton estimates for the average annual $CO_2$e reductions from 2025 through 2045 for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

**Table 3-12: Estimated average cost per metric ton of reduced $CO_2$e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (NWL)**

| Measure | Average Cost per Reduced Ton $CO_2$e ($/Ton) |
|---|---:|
| **Forests/Shrublands/Grasslands** | 15,500 |
| **Annual Croplands** | 1,100 |
| **Perennial Croplands** | 412 |
| **Urban Forest** | 3,270 |
| **Wildland Urban Interface (WUI)** | N/A |
| **Wetlands** | 64 |
| **Sparsely Vegetated Lands** | 451,000 |

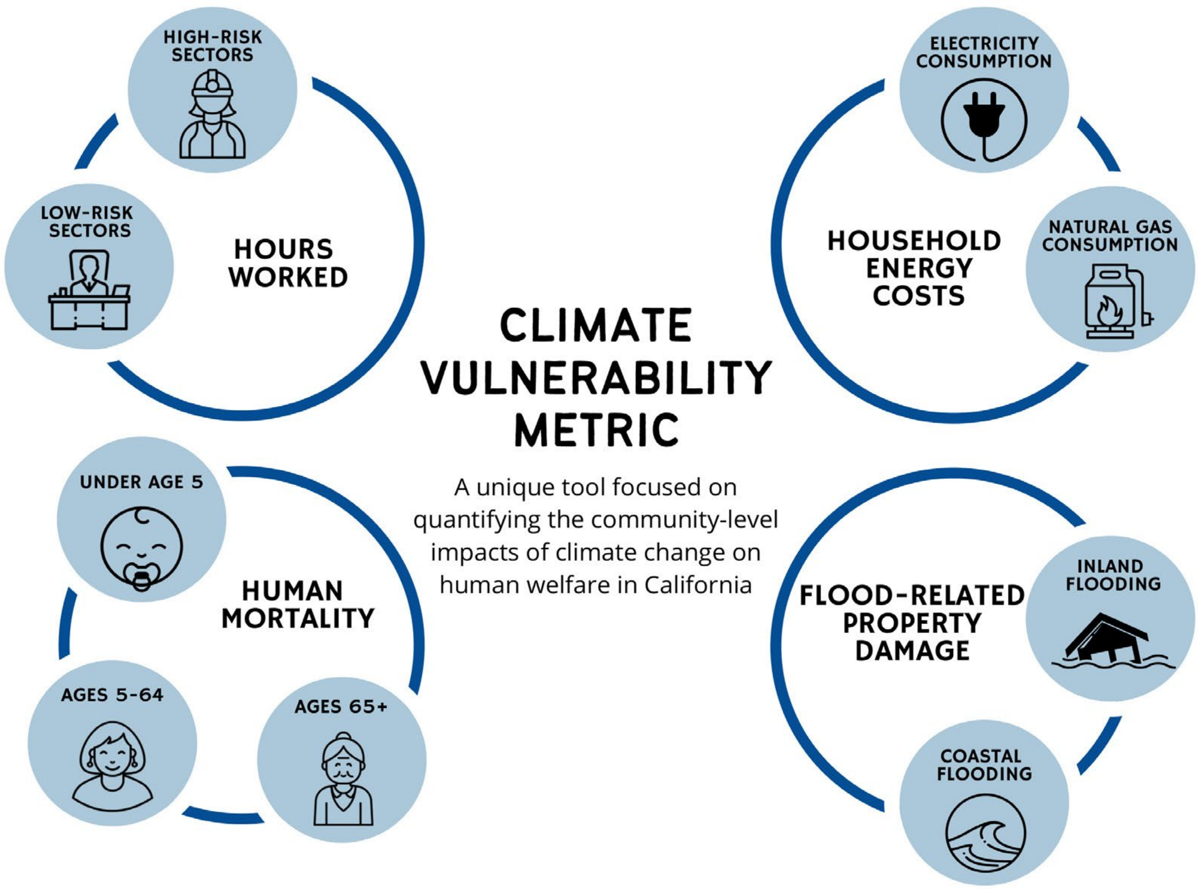
## Climate Vulnerability Metric

As California invests in climate mitigation and adaptation, it is essential to understand that the relative impact of climate change will vary across the state's communities. Due to persisting health and opportunity gaps, not all communities are equally resilient in the face of climate impacts. A global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional economic impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare and the additional costs. Additional details and results are included in Appendix K (Climate Vulnerability Metric).

The CVM aggregates the impacts of climate change that can be quantified at the census tract level using robust and currently available research. The CVM includes the projected impacts of climate change on human welfare across four categories (hours worked, household energy costs, human mortality, and flood-related property damage) through midcentury. The CVM identifies nine components of the four climate impacts as shown in Figure 3-9 and aggregates the data to generate a total CVM result for each census tract. To ensure that the CVM represents the diversity of California communities, it is reported as the aggregate monetized impact of climate change as a percentage of census tract-specific incomes.[243] For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income in that tract.

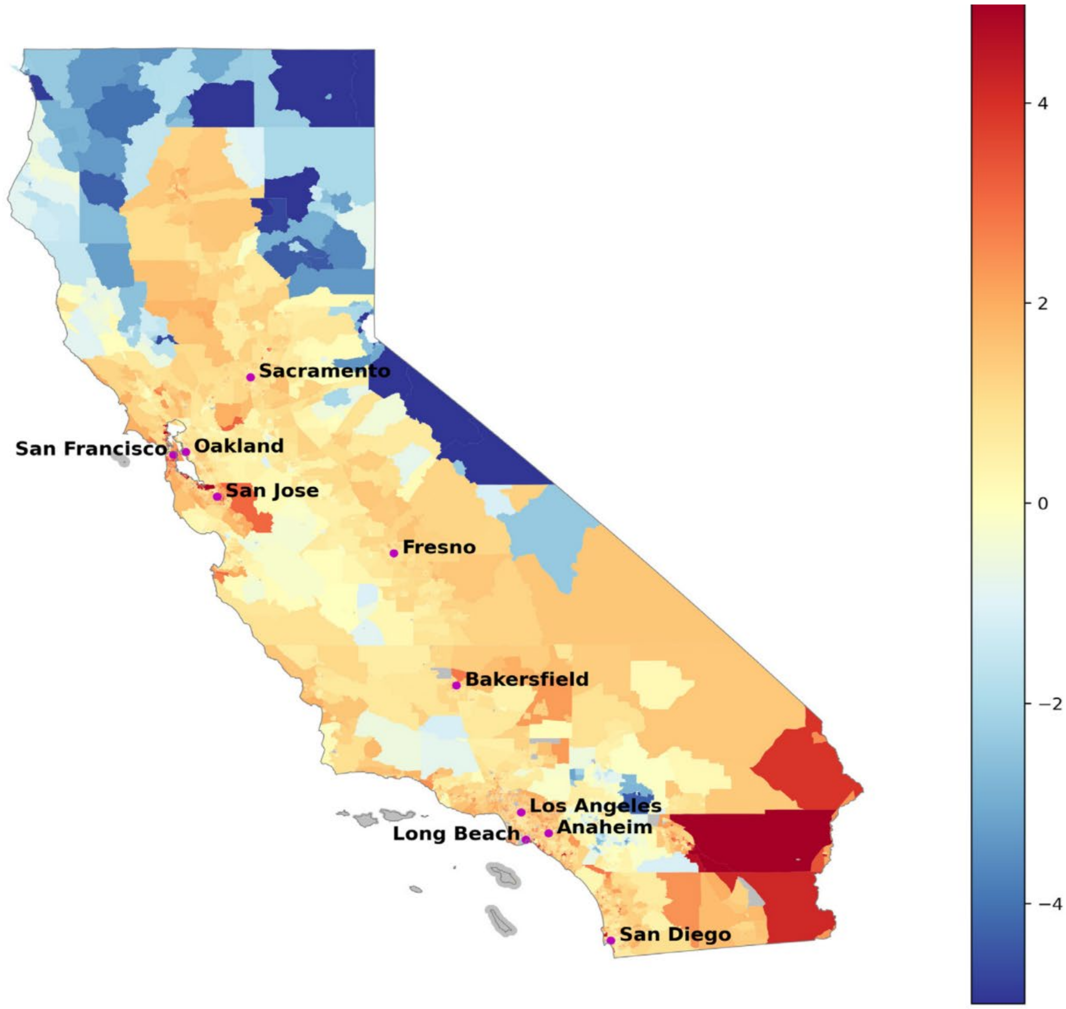
[243] Per capita income in 2019 for census tracts across California ranges from $633 to $176,388, with a median of $32,181 ($2019). Source: American Community Survey.

**Figure 3-9: Categories of climate change impacts on human welfare included in the Climate Vulnerability Metric.**




The CVM shows that climate change will have highly unequal impacts across California. While some southeastern regions of California are estimated to suffer damages that exceed 5% of annual income, other high-elevation northeastern regions of California are estimated to see benefits of up to 10%. Some low-lying urban areas, such as the San Francisco Bay Area, are estimated to be particularly vulnerable, while much of the Central Valley is estimated to suffer at least moderate economic damages relative to the rest of the state. It is important to note that the CVM does not set a threshold for vulnerability. Instead, it shows relative impacts across census tracts. The CVM is limited to the impacts that can currently be quantified at the census tract level.

**Figure 3-10: Combined impacts of climate change in 2050 under a moderate emissions scenario; damages as share of 2019 tract income (%)**




*The map shows combined impacts of climate change in 2050 under a moderate emissions scenario (RCP 4.5), reported as a share of 2019 census tract income. For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income. Impacts are combined across the categories shown in Figure 3-9. The higher the CVM for a given census tract, the more damaging the projected impacts of climate change on human welfare. Census tracts with high CVMs are represented by positive percentages in orange and red. A lower CVM is associated with lower projected impacts of climate change, shown in yellow, while a negative CVM value represents a projected beneficial impact of climate change (e.g., through reductions in deaths caused by extremely cold winter weather). Negative CVMs are represented by negative percentages in blue.*

By providing information about how climate vulnerability varies across California (Figure 3-10), the CVM results can be used to direct resources to enhance resiliency in the state's most vulnerable communities based on the specific impacts, such as heat or flooding, they are experiencing. The CVM may be used in combination with existing screening tools, such as CalEnviroScreen 4.0, to identify communities that face environmental and health hazards that contribute to disproportionate economic impacts in addition to climate vulnerability. The CVM can become an essential source of information to implement this Scoping Plan and build a more resilient, just, and equitable future for all communities.

# Public Health

## Health Analysis Overview

This section focuses on a broader evaluation of public health and climate change. Science demonstrates that taking action to address climate change presents one of the most significant opportunities to improve public health outcomes.[244] Transitioning to clean energy and technology and improving land and ecosystem management will lead to a much healthier future. Many actions to reduce GHG emissions also have health co-benefits that can improve the health and well-being of populations across the state, as well as address climate change. This section and the accompanying Appendix G (Public Health) provide a qualitative analysis of health benefits to accompany the quantitative health analysis included in this chapter, in Appendix C (AB 197 Measure Analysis), and in Appendix H (AB 32 GHG Inventory Sector Modeling). Together the qualitative and quantitative analyses of benefits are demonstrating the many ways that climate action and health improvements go hand in hand.

Climate change can lead to a wide range of direct health impacts such as increased heat-related illnesses (i.e., heat exhaustion and heat stroke), and injuries and deaths from extreme weather events or disasters (e.g., severe storms, flooding, wildfires). Indirect impacts include:

- more air pollution-related exacerbations of cardiovascular and respiratory diseases (e.g., due to increased smog, wildfire smoke)
- increased vector-borne and fungal diseases due to changes in the distribution and geographic range of disease-carrying species (e.g., mosquitoes, ticks, fungi in dust)
- negative nutritional consequences related to decreases in agricultural food yields
- stress and mental trauma due to extreme weather-related catastrophes
- anxiety, depression, and other mental health impacts associated with gradual changes in the climate (e.g., prolonged drought or temperature shifts affecting jobs and industries) that result in unemployment and income loss

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[244] Watts, N., W. N. Adger, P. Agnolucci, et al. 2015. “Health and climate change: Policy responses to protect public health.” *Lancet* 386, 1861–1914.

- residential displacement and home loss (e.g., sea level rise impacting coastal communities)

Wildfires and wildfire smoke are one area where we have already seen and expect to see even further drastic impacts on the health of Californians. According to CalFire, since 1932 the top eight largest wildfires in California have occurred in the past five years (2017–2022), with 151 deaths due directly to fires during that period.[245] Researchers estimate that wildfire smoke during fall 2020 may have led to as many as 3,000 excess deaths, with at least 95% of Californians suffering unhealthy levels of particle pollution due to wildfires in 2020.[246] Continued climate change is projected to further increase smoke exposure from wildfires through the end of the century.[247] Wildfires also create a high-risk environment for outdoor workers, including agricultural workers. While the direct medical and physical health impacts are often most noticeable, the psychological impacts can develop and persist well after the event. Estimates indicate that 20%–65% of survivors of extreme weather events have mental health issues following the event.[248]

Extreme heat, drought, and associated worsened air quality impacts are among the most serious climate-related exposures affecting the health of Californians. Numerous studies find a wide range of adverse health effects accompanying extreme heat, including heat stroke and adverse birth outcomes, and find that extreme heat can harm most body systems. Climate change exacerbates air pollution problems that cause difficulty breathing and can lead to serious illness and death in many parts of California. Increasing temperatures cause increases in ozone and other pollution concentrations, including for California's most polluted regions, and heighten health risks for the vulnerable and marginalized populations living in these areas.[249] In 2020, there were 157 ozone polluted days across Los Angeles, Orange, Riverside, and San Bernardino Counties—the most days since 1997. In addition, particulate matter exposure is a heightened problem during

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[245] California Department of Forestry and Fire Protection (CAL FIRE). "Stats and Events." *Cal Fire Department of Forestry and Fire Protection*, https://www.fire.ca.gov/stats-events/.

[246] G-FEED. 2020. Indirect mortality from recent wildfires in CA. *http://www.g-feed.com/2020/09/indirect-mortality-from-recent.html*.

[247] M. D. Hurteau, A. L. Westerling, C. Wiedinmyer, and B. P. Bryant. 2014. "Projected effects of climate and development on California wildfire emissions through 2100." *Environ. Sci. Technol.* 48, 2298–2304.

[248] American Public Health Association. 2019. Addressing the Impacts of Climate Change on Mental Health and Well-Being. Policy No: 20196. *https://www.apha.org/policies-and-advocacy/public-health-policy-statements/policy-database/2020/01/13/addressing-the-impacts-of-climate-change-on-mental-health-and-well-being*.

[249] American Lung Association. State of the Air 2021. *https://www.lung.org/research/sota*.

droughts, which are expected to increase over this century.[250,251] Worse air quality leads to illnesses, emergency room visits, and hospitalizations for chronic health conditions, including chronic obstructive pulmonary disease (COPD), asthma, chronic bronchitis, and other respiratory and cardiovascular conditions, as well as increased risk for respiratory infections, which all result in greater health costs to the state.[252,253,254] These and other climate-related health impacts are discussed in more detail in Appendix G (Public Health).

## Health Analysis Components

This Scoping Plan health analysis focuses on the contrast between a California that is still dependent on a fossil fuel-based economy and a California that is transitioned to a carbon-neutral, clean energy future. This qualitative analysis evaluates and demonstrates the broad range of benefits of a dramatic reduction in fossil fuels by 2045 combined with healthier ecosystem management, comparing health outcomes for a “no-action” scenario (Reference) to a “take-action” decarbonization scenario. As this is a qualitative analysis, it looks more broadly at the public health benefits of a drastic reduction in fossil fuel combustion. While this analysis provides scientific evidence for Scoping Plan benefits based on achieving carbon neutrality by 2045, it does not analyze a specific scenario.

The key areas of focus for the analysis are: heat impacts, children’s health and development, economic security, food security, mobility and physical activity, urban greening, wildfires and smoke impacts, and housing affordability. For each area of focus, the analysis covers the scientific evidence and compares expected health effects between the Reference and decarbonization scenarios. This analysis looks at the major health outcomes, provides directional effects for each health outcome, and where possible provides information on the strength and scale of health impacts. Some areas include quantitative information where tools are available to measure health outcomes. While the analysis is focused on health outcomes statewide, it also includes discussion

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[250] Cvijanovic, I., B. D. Santer, C. Bonfils, et al. 2017. “Future Loss of Arctic Sea-ice Cover Could Drive a Substantial Decrease in California’s Rainfall.” 8 *Nat. Commun.* 1947. https://doi.org/10.1038/s41467-017-01907-4.

[251] Williams, A. P., R. Seager, J. T. Abatzoglou, B. I. Cook, J. E. Smerdon, and E. R. Cook. 2015. “Contribution of anthropogenic warming to California drought during 2012–2014.” *Geophysical Research Letters* 42(16), 6819–6828.

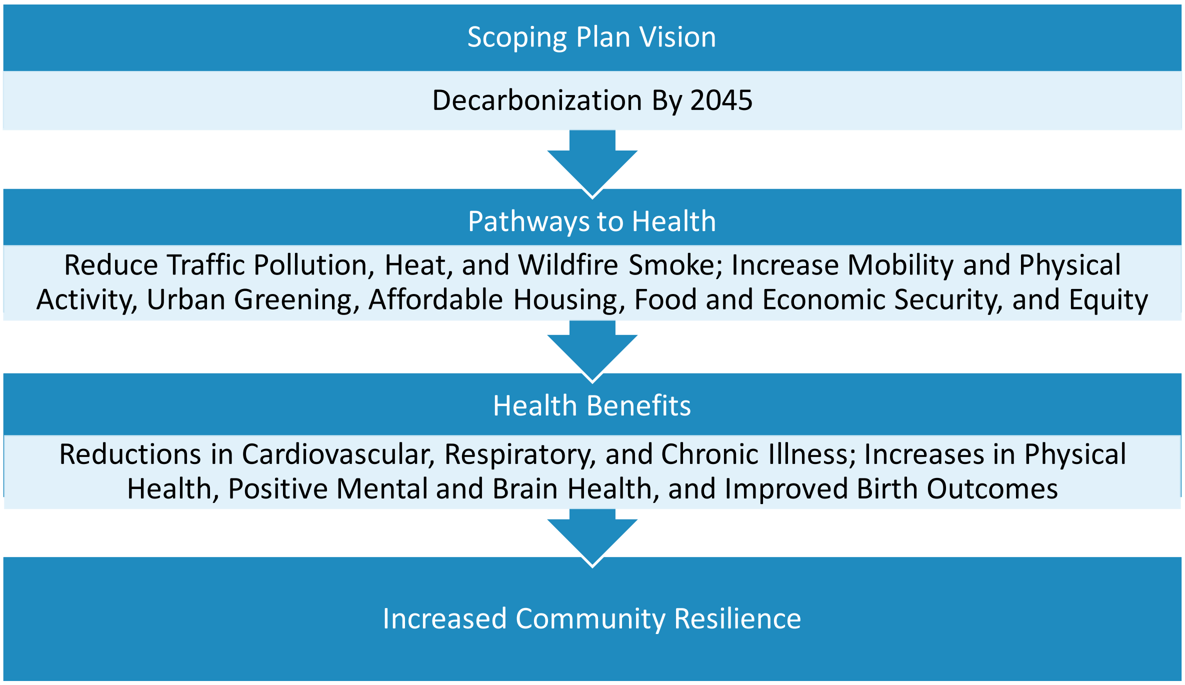
[252] Romley, J. A., A. Hackbarth, and D. P. Goldman. 2010. Cost and Health Consequences of Air Pollution in California. Santa Monica, California. RAND Corp. https://www.rand.org/pubs/research_briefs/RB9501.html.

[253] Wang, M., C. P. Aaron, J. Madrigano, E. A. Hoffman, E. Angelini, J. Yang, A. Laine, et al. 2019. “Association between long-term exposure to ambient air pollution and change in quantitatively assessed emphysema and lung function.” *JAMA* 322(6), 546–556.

[254] Inserro, A. 2018. “Air Pollution Linked to Lung Infections, Especially in Young Children.” *Am. J. Managed Care* (May 6). https://www.ajmc.com/view/air-pollution-linked-to-lung-infections-especially-in-young-children.

of benefits to community health and climate resilience, as well as potential inequities experienced at a community level. Figure 3-11 shows the co-benefit areas covered in this Scoping Plan and the path to health improvements and increased community resilience.

**Figure 3-11: Scoping Plan outcome and the path to health improvements**



## Social and Environmental Determinants of Health Inequities

Communities across the state do not experience exposure to pollution sources and the resulting effects equally. Low-income communities and communities of color (including Black, Latino and Indigenous communities) consistently experience significantly higher rates of pollution and adverse health conditions than others due to factors including historic marginalization rooted in systemic racism. As shown in Figure 3-12, the most impacted neighborhoods according to CalEnviroScreen (CES) are home to very high percentages of people of color while the least impacted neighborhoods are predominantly white. Recent findings show that Black Californians have 19% higher $PM_{2.5}$ exposure from vehicle emissions than the state average, and the census tracts with the highest $PM_{2.5}$ pollution burden from vehicle emissions have a high proportion of people of color.[255] Air pollutant emissions from mobile sources have disproportionate impacts on low-income communities and communities of color due to their proximity.[256] Diesel-fueled vehicles traveling on California's freeways and major roads expose nearby residents to pollution that is linked to lung cancer, hospitalizations and emergency department visits for chronic heart and lung disease, and premature death.[257,258] A combination of historical and social inequities are evident in communities of color disproportionately living close to freeways and other major sources of vehicle pollution. Environmental exposures and contaminants are one component of a broader set of social, economic, and environmental factors that can amplify health conditions, and the combination of all these factors can compound the health effects of individual exposures. This broader set of community factors can be referred to as "cumulative impacts." In addition, specific populations are more sensitive to pollution and face greater susceptibility. This includes young children, older adults, and individuals with existing health conditions.

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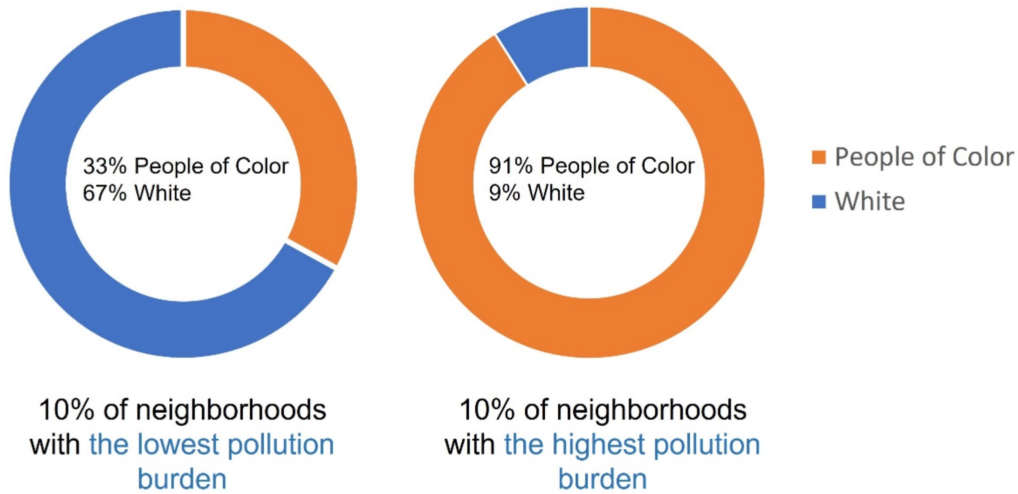
[255] Reichmuth, D. 2019. *Inequitable exposure to air pollution from vehicles in California.* https://www.ucsusa.org/resources/inequitable-exposure-air-pollution-vehicles-california-2019.

[256] CARB. 2017. *California's 2017 climate change scoping plan.* https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

[257] CARB. 2020. Overview: Diesel exhaust & health. https://ww2.arb.ca.gov/resources/overview-diesel-exhaust-and-health.

[258] Kagawa, J. 2002. "Health effects of diesel exhaust emissions—a mixture of air pollutants of worldwide concern." *Toxicology* 181–182:349–353.

**Figure 3-12: Least and most impacted neighborhoods from CalEnviroScreen[259]**




### Social Determinants of Health Inequities

The physical and mental health of individuals and communities is shaped, to a great extent, by the social, economic, and environmental circumstances in which people live, work, play, and learn. According to the World Health Organization, these same circumstances—or social determinants of health—are "mostly responsible for health inequities: the unfair and avoidable differences in health status seen within and between countries." In fact, a strong body of research demonstrates that more than 50 percent of long-term health outcomes are the result of social determinants affecting an individual.[260] Race/ethnicity and socioeconomic status, for example, have been found to amplify impacts from long- and short-term environmental exposures for several health outcomes,

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[259] The figure represents the top and bottom decile scoring of CalEnviroScreen census tracts for pollution burden. This chart is modified from Figure 2. Race in the Least and Most Impacted Census Tracts of CalEnviroScreen 4.0 in the Office of Environmental Health Hazard Assessment, California Environmental Protection Agency. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. 2021. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

[260] California Department of Public Health (CDPH). 2015. *The Portrait of Promise: The California Statewide Plan to Promote Health and Mental Health Equity.* A Report to the Legislature and the People of California by the Office of Health Equity. Sacramento, California. California Department of Public Health, Office of Health Equity.

such as mortality and birth outcomes.[261,262,263,264] Social factors combine in low-income communities and communities of color to create levels of toxic chronic stress and limit opportunities for healthy food and healthy lifestyles. Social factors also can cause health disparities through psychosocial pathways such as discrimination and social exclusion.[265] While the importance of social determinants is well known, measuring the specific and cumulative impacts of social determinants is challenging.

There are several important tools to evaluate and map cumulative impacts and factors contributing to the results of historical practices such as redlining, and these tools have been used for air quality and climate planning, community protection, and investments. CalEnviroScreen is a tool that maps cumulative pollution burdens and vulnerabilities on a statewide basis and ranks census tracts based on environmental, exposure, population, and socioeconomic indicators. An analysis using CES shows a direct, persistent relationship between exposure to environmental burdens and socioeconomic and health vulnerabilities affecting communities of color and historical redlining practices. OEHHA has evaluated health impacts of certain climate change policies on disadvantaged communities and communities of color utilizing CES rankings.[266] The Healthy Places Index (HPI) maps indicators that affect life expectancy on a statewide basis. In the future, these and other tools can be helpful to prioritizing investments and informing implementation efforts for GHG emission reductions policies.

## Environmental Determinants of Health Inequities

Communities with large percentages of Black and other socially vulnerable and marginalized groups are disproportionately located near pollution sources, such as traffic

[261] O'Neill, M. S., M. Jerrett, I. Kawachi, J. I. Levy, A. J. Cohen, N. Gouveia, et al. 2003. "Health, wealth, and air pollution: Advancing theory and methods." *Environ Health Perspect.* 111 (16): 1861–70.

[262] Ponce, N. A., K. J. Hoggatt, M. Wilhelm, and B. Ritz. 2005. "Preterm birth: The interaction of traffic-related air pollution with economic hardship in Los Angeles neighborhoods." *Am J Epidemiol.* 162 (2): 140–8.

[263] Morello-Frosch, R., B. Jesdale, J. Sadd, and M. Pastor. 2010. "Ambient air pollution exposure and full-term birth weight in California." *Environ Health.* 9: 44.

[264] Finkelstein, M. M., M. Jerrett, P. DeLuca, N. Finkelstein, D. K. Verma, K. Chapman, et al. 2003. "Relation between income, air pollution, and mortality: A cohort study." *CMAJ.* 169 (5): 397–402.

[265] Clougherty, J., and L. Kubzansky. 2009. "A framework for examining social stress and susceptibility in air pollution and respiratory health." *Environ Health Perspect.* 117 ( 9 ): 1351–8.

[266] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities.* https://oehha.ca.gov/media/downloads/environmental-justice//impactsofghgpoliciesreport020322.pdf.

and freight facilities, industrial facilities, and hazardous waste sites.[267,268,269,270] Research shows large disparities in exposure to pollution between white and non-white populations in California, and between low-income and communities of color (Figure 3-13). The research also shows Black and Latino populations experience significantly greater air pollution impacts than white populations in California.[271] Additionally, Native Americans are disproportionately impacted by air pollution with high rates of exposure to industrial, diesel, and residential pollution sources and higher rates of diseases linked to air pollution.[272, 273]

[267] Mohai. P., P. M. Lanz, J. Morenoff, J. S. House, and R. P. Mero. 2009. "Racial and socioeconomic disparities in residential proximity to polluting industrial facilities: Evidence from the Americans' Changing Lives Study." *Am J Public Health.* 99 (Suppl 3): S649–56.

[268] Mohai, P., and R. Saha. 2007. "Racial inequality in the distribution of hazardous waste: A national-level reassessment." *Soc Probl.* 54 (3): 343–70.

[269] Morello-Frosch, R., M. Pastor, C. Porras, and J. Sadd. 2002. "Environmental justice and regional inequality in southern California: Implications for future research." *Environ Health Perspect.* 110 (Suppl 2): 149–54.

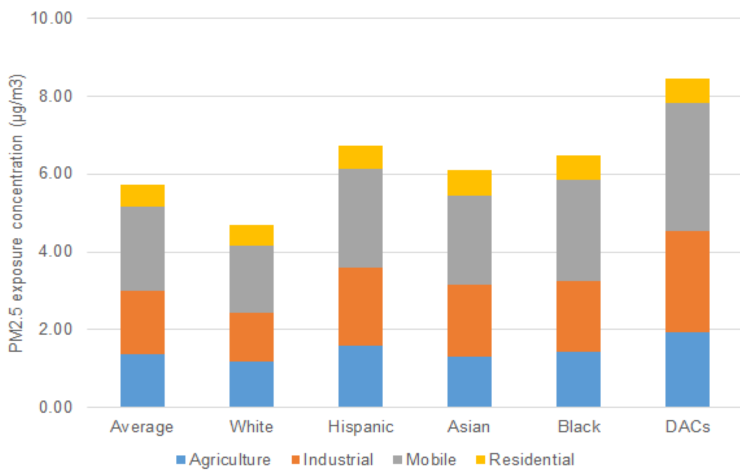
[270] Gunier, R. B., A. Hertz, J. von Behren, and P. Reynolds. 2003. "Traffic density in California: Socioeconomic and ethnic differences among potentially exposed children. *J Expo Anal Environ Epidemiol.* 13 (3): 240–6.

[271] Apte, J. S., S. E. Chambliss, C. W. Tessum, and J. D. Marshall. 2019. *A Method to Prioritize Sources for Reducing High $PM_{2.5}$ Exposures in Environmental Justice Communities in California.* CARB Research Contract Number 17RD006.

[272] Indigenous People and Air Pollution in the United States. A Report from the National Tribal Air Association and Moms Clean Air Force. 2021. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2021/04/indigenousairpollution_041421.pdf

[273] National Tribal Air Association. 2022. Status of Tribal Air Report. Pg. 66. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2022/10/2022-NTAA-Status-of-Tribal-Air-Report.pdf.

**Figure 3-13: Top sources of $PM_{2.5}$ and their contribution to $PM_{2.5}$ exposures by race and in disadvantaged communities**




These disparities in exposure to pollution sources generate health inequities. Communities located near major roadways are at increased risk of asthma attacks and other respiratory and cardiac effects. Studies consistently show that mobile source pollution exposure near major roadways or freight sources contributes to and exacerbates asthma, impairs lung function, and increases cardiovascular mortality.[274] The exposure to mixtures of gaseous and particulate pollutants in mobile sources (including PM, $NO_x$, and benzene) is associated with higher rates of heart attacks, strokes, lung cancer, autism, and dementia.[275]

Environmental hazards found in communities also can include exposures to toxic substances and emissions, as well as occupational exposures. Due to historical inequities, under-resourced communities and communities of color are often located close to sources of toxic pollution, including chrome platers; metal recycling facilities; oil and gas operations; agricultural burning; railyards; facilities transporting, managing, or disposing of hazardous waste; and areas impacted by pesticides, among others. Some populations may be at increased risk of exposure to pollutants, both at work and home.

Children are more susceptible to environmental pollutants for many reasons, including the ongoing development of their nervous, immune, digestive, and other bodily systems. Moreover, children eat more food, drink more fluids, and breathe more air relative to their

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[274] U.S. Environmental Protection Agency website. How Mobile Source Pollution Effects Your Health. https://www.epa.gov/mobile-source-pollution/how-mobile-source-pollution-affects-your-health.

[275] USC Environmental Health Centers. 2018. Living Near Busy Roads or Traffic Pollution. https://envhealthcenters.usc.edu/wp-content/uploads/2016/10/living-near-bus_19696172.pdf.

body weight, as compared to adults.[276] Exposure to high levels of air pollutants, including indoor air pollutants, increases the risk of respiratory infections, heart disease, and asthma.[277] Children living in low-income communities near industrial operations, rail yards, and heavily trafficked freeways and streets in urban areas are at especially high risk of chronic respiratory conditions. Black children are four times more likely to be hospitalized for asthma compared with white children, and urban Black and Latino children are two to six times more likely to die from asthma than white children.[278] Native American children also experience more impacts from asthma and Native American children, along with Black children, have the highest prevalence of asthma.[279]

For older adults, increased vulnerability is linked to respiratory, cardiovascular, and immune systems weakened by aging.[280] Preexisting health conditions interact with environmental pollutants to enhance risks of adverse health outcomes.[281,282] The recent COVID-19 pandemic has highlighted the heightened vulnerability of older adults as well as communities of color to respiratory disease, as hospital admissions and mortality data linked to COVID-19 cases for these groups have been higher than other groups. Research has also underscored the important link between COVID-19 mortality and morbidity and air pollution, demonstrating significantly higher mortality and morbidity for COVID-19 in areas of elevated $PM_{2.5}$ pollution.

## Climate Vulnerabilities

Climate change is expected to exacerbate the existing disparities of health conditions and worsen climate vulnerability, which is the degree to which natural systems and people or

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[276] Blaisdell, R. J. Air Toxics Hot Spots Program Risk Assessment Guidelines. 2012. Technical Support Document for Exposure Assessment and Stochastic Analysis. Oakland, California: California Environmental Protection Agency, Office of Environmental Health Hazard Assessment. August.
[277] Woodruff, T. J., D. A. Axelrad, A. D. Kyle, O. Nweke, and G. G. Miller. 2003. *America's Children and the Environment: Measures of Contaminants, Body Burdens, and Illness.* 2nd ed. Washington, D.C.: United States Environmental Protection Agency. February.
[278] California Department of Public Health. Asthma Inequities in California Children. 2021. https://www.cdph.ca.gov/Programs/CCDPHP/DEODC/EHIB/CPE/CDPH%20Document%20Library/CA_Asthma_Inequities_Children_2021-Infographic.pdf.
[279] Meng, Y., S. H. Babey, T. A. Hastert, and E. Brown. 2007. California's Racial and Ethnic Minorities More Adversely Affected by Asthma. UCLA: Center for Health Policy Research. Retrieved from https://escholarship.org/uc/item/4k45v3xt.
[280] Sandström, T., A. J. Frew, M. Svartengren, and G. Viegi. 2003. "The need for a focus on air pollution research in the elderly." *Eur Respir J Suppl.* 40: 92s–5s.
[281] Zanobetti, A., and J. Schwartz. 2001. "Are diabetics more susceptible to the health effects of airborne particles?" *Am J Respir Crit Care Med.* 164 (5): 831–3. https://www.atsjournals.org/doi/pdf/10.1164/ajrccm.164.5.2012039.
[282] Zanobetti, A., J. Schwartz, and D. Gold. 2000. "Are there sensitive subgroups for the effects of airborne particles?" *Environ Health Perspect.* 108 (9): 841–5.

communities are at risk of experiencing the negative impacts of climate change.[283] A report from the California Climate Change Center warned that the impacts of climate change will likely create especially heavy burdens on low-income and other vulnerable populations: "*Without proactive policies to address these equity concerns, climate change will likely reinforce and amplify current as well as future socioeconomic disparities, leaving low-income, minority, and politically marginalized groups with fewer economic opportunities and more environmental and health burdens*."[284]

In the U.S. Environmental Protection Agency's "Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts,"[285] investigators analyzed risks of six primary climate change impacts disproportionately affecting communities across income, educational attainment, race/ethnicity, and age groups. Four socially vulnerable populations—low income, communities of color, no high school diploma, and age 65 and older—were identified as having a higher likelihood of experiencing the greatest impacts of a changing climate (according to the projected 2°C of global warming or 50 centimeters of global sea level rise). Disproportionate impacts were projected for climate events, including air quality, extreme temperature, coastal flooding, and other impacts, leading to increased risk of health and other adverse outcomes. The study projected significant health impacts for low-income communities, certain racial and ethnic subgroups, and those with lower educational attainment.

Several climate vulnerability tools have been developed or are under development to better understand and map areas at higher risk of climate impacts. The Climate Change and Health Vulnerability Indicators (CCHVIs) for California helps state and local health officials prepare for and reduce adverse health impacts due to a changing climate.[286] For example, Los Angeles County shows higher than state average climate vulnerability overall, particularly for those who are linguistically isolated (more than twice the state average).

In summary, there are many environmental, social, individual, and economic factors affecting health and equity in California and contributing to worsening health outcomes from climate change impacts. This section and Appendix G (Public Health) reference a substantial and growing body of research documenting the different social and

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[283] OPR. 2018. Defining Vulnerable Communities in the Context of Climate Adaptation. https://opr.ca.gov/docs/20180723-Vulnerable_Communities.pdf.

[284] Shonkoff, S., R. Morello-Frosch, M. Pastor, and J. Sadd. 2011. "The climate gap: environmental health and equity implications of climate change and mitigation policies in California—A review of the literature." *Climatic Change* 109 (Suppl 1): S485–S503.

[285] U.S. EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency. EPA 430-R-21-003.

[286] CDPH. 2022. Climate Change and Health Vulnerability Indicators for California. California Department of Public Health. https://www.cdph.ca.gov/Programs/OHE/Pages/CC-Health-Vulnerability-Indicators.aspx.

environmental factors affecting health outcomes and the many groups that are vulnerable to increased effects or that experience health inequities in California (see Table 3-13).

**Table 3-13: Examples of vulnerable groups due to socioeconomic, environmental, developmental, and climate change factors**

| Examples of Vulnerable Groups Due to Socioeconomic, Environmental, Developmental, and Climate Change Factors | | |
|---|---|---|
| Older People | People with Existing Chronic Illness | People Impacted Due to Working Conditions |
| Tribal Groups | Infants and Children | Low-Income People |
| People with Disabilities | People Experiencing Homelessness | Pregnant People |
| Communities of Color | Marginalized People | Immigrants/Refugees |
| People with Less Educational Options | Linguistically Isolated Households | People Impacted Due to Poor Housing Conditions |

## Summary of the Qualitative Health Analysis

CARB has developed a detailed health analysis that covers eight social and environmental co-benefit areas that impact public health (listed below). These co-benefit areas were selected due to ongoing research in these areas as well as discussion in a public workshop on climate change and health impacts held in summer 2018. For each social and environmental area, the analysis includes:

- a discussion of health impacts and disparities,
- key health metrics or epidemiological research on this topic,
- a discussion of how these areas would be affected by “no-action” (i.e., Reference) scenario compared to a “take-action” (i.e., Scoping Plan) scenario
- a discussion of where there are actions to consider for further success, and
- the types of mitigation actions that can help reduce or eliminate disparities and promote greater health equity and resilience.

All co-benefit areas are interconnected, and pursuing benefits in all areas has the potential to multiply positive results and further support building community resilience. *Community resilience* is the ability of a community to reduce harm and maintain an acceptable quality of life in the face of climate-induced stresses, which vary depending on that community’s circumstances and location. Below is a brief description of the areas evaluated for public health co-benefits. The specific health outcomes impacted by each area, as well as the directional health benefits, are included in the Summary of Health Benefits section of the chapter and covered in more detail in Appendix G (Public Health).

## Heat Impacts

Globally, increased GHG concentrations in the atmosphere are causing a continuing increase of the planet's average temperature. California temperatures have risen since records began in 1895, and the rate of increase is accelerating. Recent heat waves have broken heat records and caused serious illness across the state, and these events are becoming more frequent. Heat waves have a particularly high impact in Southern California, where they have become more intense and longer lasting. In the past two years, Los Angeles recorded 121°F, and the Coachella Valley had its hottest year ever, with temperatures reaching 123°F. Heat island effects in urbanized areas can elevate heat effects and disproportionately affect low-income communities and communities of color. Heat events exacerbate respiratory and cardiac illness and cause emergency room visits to soar. Strategies that reduce the impacts of heat exposure promote improved health outcomes.

## Wildfires and Smoke

California's NWL cover more than 90 percent of California and include rangeland, forests, woodlands, grasslands, and urban green space. They provide biodiversity and ecosystem benefits, including their ability to sequester carbon from the atmosphere. Protecting and managing California's forests and other natural lands and maintaining their ecosystem health are key practices for maximizing GHG benefits and minimizing negative climate change impacts. Vegetation plays an important role in storing carbon; however, it can also release $CO_2$ back into the atmosphere when it dies or is burned by fires. California's wildfires are getting worse with increased fire risks, higher frequency of occurrence, larger burn areas, more costly damage, and a longer fire season due to climate change. Strategies that promote healthy ecosystem management of natural and working lands and increased urban greening promote improved health outcomes. Healthy ecosystems provide many health and environmental benefits and can maximize carbon sequestration.

## Children's Health and Development

There are a wide range of interconnected environmental, social, biological, and community factors associated with climate change that are adversely affecting children's health. This section focuses on air pollution and near-roadway or traffic pollution as environmental impacts that have a profound effect on children's health. Children's bodies and lungs are still developing, and they take in more air per body weight than adults do. Many low-income communities and communities of color in California experience disproportionately high levels of air pollution, as well as high levels of traffic and freight that impact children. This excess exposure harms children's development and predisposes them to increased risk of illness throughout their lives. Strategies that reduce air pollution and traffic emissions promote improved health outcomes for children.

## Economic Security

Climate change is expected to result in serious adverse socioeconomic effects across many sectors. Economic factors, such as income inequality (among geographic regions), poverty, wealth, debt, unemployment rate, and job security are among the strongest determinants of health. Along the entire income spectrum, higher income is associated with increased life expectancy and improved health outcomes in the United States. Additionally, economic insecurity and negative health impacts are more pronounced in low-income communities and communities of color. Economic strategies, such as the promotion of clean energy and other green jobs and investments in low-income communities and communities of color, and promoting a transition to high road jobs in economic sectors tied to the current fossil fuel economy, can promote improved health outcomes.[287]

## Food Security

The food system is under pressure from numerous factors, and climate change is a key concern. Climate change can affect food production and agricultural yield, impact culturally significant plants and animals for Native American tribes, and exacerbate factors that limit food availability, such as supply chain disruption. Food security is defined as stable access to affordable, sufficient food for an active, healthy life. Many Californians routinely experience food insecurity, and while that impacts Californians of all races and groups, low-income communities and communities of color and children are disproportionately affected by food insecurity. Many Native Americans depend on resources from the land, such as animals and plants for consumption and cultural practices. Strategies that promote sustainable agriculture, access to healthy foods, and reduced organic food waste promote improved health outcomes.

## Mobility and Physical Activity

Physical activity is one of the most important factors for a healthy lifestyle, and lack of activity increases the risk of chronic illness and premature death. Research shows that regular physical activity improves health in people of all ages by improving heart and lung

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[287] According to the California Labor and Workforce Development Agency's High Road Training Partnership program, high road jobs are considered "Quality jobs [that] provide family-sustaining wages, health benefits, a pension, worker advancement opportunities, and collective worker input and are stable, predictable, safe and free of discrimination." https://cwdb.ca.gov/wp-content/uploads/sites/43/2020/08/OneSheet_Job-Quality_ACCESSIBLE.pdf.

function, muscle fitness, mental health and brain function, and sleep quality. A sedentary lifestyle contributes to chronic illnesses, including obesity, heart disease, and Type 2 diabetes among other chronic illnesses. Promoting community design that supports sustainable patterns of land use and transportation enables active transportation choices like walking, biking, and public transit over driving, and can significantly increase physical activity, leading to many valuable health benefits.

### Affordable Housing

Housing is an important social determinant of health. The stability of housing, housing quality, conditions inside and outside the home, the cost of housing, and the environmental and social characteristics of the places people live all affect health (including energy efficiency and insulation, cooler building material, tree canopy, home size). Housing affordability is a key factor, and this section highlights how housing affordability supports not only improved health but also more sustainable land use and transportation patterns. A lack of affordable housing is increasing commute distances for low-income renters and creating health burdens. Strategies that support sustainable transportation and housing patterns, together with increased housing affordability, promote improved health outcomes.

### Urban Greening

Urban Greening is well recognized as an important amenity, but the inherent health benefits are not always well understood. Under-resourced and vulnerable areas consistently show a lack of urban greening and higher percentages of concrete, asphalt, and impervious surfaces. Under-resourced communities have a greater proportion of concrete and heat-trapping surfaces and a lower amount of tree cover in the neighborhoods in which they live. Areas with reduced urban greening have the potential to create areas of higher temperatures as heat is reflected from pavements and buildings. By contrast, increasing urban greening can provide air pollution buffers and promote physical activity. Strategies that preserve and create urban parks, green space, natural infrastructure, and sustainable agricultural practices support improved physical and mental health outcomes.

### No Action Scenario (Reference)

In a no-action scenario, California would remain dependent on fossil fuels and other GHG emitting technologies. Fossil-fuel powered mobile sources including cars, trucks, trains, tractors, and a myriad of other on-road and off-road vehicles and equipment are the largest source of criteria pollutants and toxic air contaminants that directly affect community health and contribute the largest portion of GHG emissions.[288] Other key GHG emission sources include buildings, natural and working lands, and power production and industry. The no-action scenario reflects a continued reliance on fossil fuels in mobile and stationary sectors, including buildings. The continued production and use of fossil fuels; ongoing dependence on gasoline and diesel cars, trucks, buses, and equipment; continued releases of short-lived climate pollutants; and decreased emphasis on forest and ecosystem health will impact communities by reducing climate resilience and health benefits. Green space will likely remain at the same levels or degrade, and urban heat islands will likely increase. With continued growth of vehicle miles traveled, physical activity and the accompanying health benefits will not increase.

Exposure to wildfire smoke will increase, and air quality is expected to worsen as rising temperatures will increase levels of harmful air pollution. Jobs and economic security will be affected by the continuing potential for price spikes in fossil fuels, impacts to the economy from climate change, and fewer job opportunities in green technologies such as solar and electric vehicles. Food security in California will decrease due to the effects of accelerating climate impacts to agriculture; and without increased recovery of organic waste, including food products, food security will continue to decline under a no action scenario. All these impacts can be linked to worse health outcomes. Adverse health impacts are often most felt by Black, Latino, Native American, and other people of color and in low-income communities. These groups are affected more intensely by the physical stress of environmental pollution, social inequities, and the psychological stress of extreme weather events and food and economic insecurity.

### Take Action Scenario

In the Take Action scenario, California will drastically reduce reliance on fossil fuels for motor vehicles, freight, buildings, electricity, or other sectors. This scenario is not a specific scenario within this Scoping Plan but examines the broad outcomes of actions to achieve carbon neutrality in 2045. Implementation of this Scoping Plan would achieve a transition to ZEVs, with 100% sales of light-duty ZEVs by 2035 and 100% sales of zero emission trucks by 2040, along with 30% VMT reductions below 2019 levels by 2045. State and local action that supports sustainable land use and transportation patterns and enables more transit and active transportation will lead to substantial health benefits from physical activity, including reduced illness and deaths.

[288] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

The economic benefits of improved health through active transportation can be modeled using the Healthy Mobility Options Tool (HMOT).[289] In order to demonstrate the important health and economic benefits of VMT reduction, CARB and CDPH used the HMOT to analyze an illustrative trip reduction scenario for 2050 from the California Transportation Plan (CTP). The CTP has a goal of increasing active modes of travel and transit from the current level of 13 percent to a level of 23 percent of all travel trips. While the CTP goal of 23 percent for active modes of travel is not a VMT reduction target, the scenario increases active transportation through a mix of changes in land use planning for increased transportation options, including increases in biking, walking, and transit use, and it helps to show the health benefits of increased active transportation. By achieving the CTP 2050 goals, nearly 8,000 deaths would be avoided in 2050 alone (see Figure 3-14), along with significant reductions in chronic diseases. Achieving this would rank among the top public health accomplishments (see Appendix G [Public Health] for additional modeling results and detailed discussion).

The dramatic reduction in fossil fuel combustion, combined with reductions in VMT and freight and traffic emissions projected in this Scoping Plan will significantly reduce air pollution and its associated health impacts on a statewide basis and in communities near freight sources. Coordinated action strategies will emphasize natural and working lands management changes, including healthy forests, increased vegetative cover, and increased organic farming. Wildfire smoke exposure will reduce significantly with healthy ecosystem management strategies. Since many communities in California are disproportionately impacted by high levels of traffic pollution, the reduction in petroleum fueled vehicles will reduce the additional impacts of living or going to school near historically highly polluting sources. Indoor air quality is also likely to improve through a shift to non-fossil fuel appliances. Concerted state and local action to support sustainable land use and transportation patterns can enable more active transportation with health benefits from physical activity.

[289] ITHIM California. 2020. Transportation Planning for Health, Equity, and Climate Change. https://skylab.cdph.ca.gov/HealthyMobilityOptionTool-ITHIM/.

**Figure 3-14: Quantified health benefits of active transportation from increased physical activity**

**8,000 avoided deaths**

from increasing Active Transportation*

*Calculated by the Healthy Mobility Options Tool, active transportation (including walking, rolling, cycling, and taking public transit) from the California Transportation Plan 2050 compared to business as usual for 2050.

Overall community resilience is expected to increase as physical activity and green space increases—potentially decreasing urban heat islands. Efforts to support VMT reduction will include coordination across state agencies on affordable housing measures. Reduced fossil fuel dependence will reduce economic pressure from wildfires, droughts, and price spikes in fossil fuels, especially as more jurisdictions implement plans with similar actions. Investment in sustainable agriculture, healthy forests, urban greening, and clean energy technologies will add sustainable jobs and further promote economic security. More sustainable agriculture and food recovery efforts will add to food security. All these impacts can be linked to wide ranging health benefits, including positive respiratory and cardiovascular effects, healthier birth and brain outcomes, improved mental health indicators, improved life expectancy, reductions in chronic illness and cancers, improved children's health and development, reduced depression, and other benefits. The magnitude of the possible co-benefits is extremely large, especially in areas that are currently the most affected.

## Summary of Health Benefits

Below, Tables 3-14 and 3-15 show overall summaries of the directional benefits by co-benefit area estimated for this Scoping Plan. The supporting epidemiological studies used for qualitative or quantitative analysis of each co-benefit area are included in Appendix G (Public Health). Another section of Chapter 3, together with Appendix C (AB 197 Measure Analysis) and Appendix H (AB 32 GHG Inventory Sector Modeling), also includes the quantitative analysis of air pollution related health impacts, including recently added health endpoints for CARB's ongoing analysis.

**Table 3-14: Scoping Plan directional benefits for health co-benefit areas (heat, affordable housing, food security, economic security, and urban greening)**

| | Health Co-benefit Areas* | | | | |
|---|---|---|---|---|---|
| **Quantitative vs. Qualitative** | **Reduced Heat Impacts** | **Increased Affordable Housing** | **Increased Food Security** | **Increased Economic Security** | **Increased Urban Greening** |
| **Research was used for Qualitative Analysis** | ↓ Mortality<br>↓ Emergency Room Visits for cardiovascular and respiratory causes and intestinal infections<br>↓Hospitalization for cardiovascular, respiratory causes<br>↓ Preterm Birth<br>↓ Mental Illness | ↓ Infectious Disease<br>↓ Chronic Illness<br>↓ Asthma<br>↓ Injuries<br>↓ Mental Illness<br>↑ Children's Performance in Schools<br>↑ Children's Health<br>↓ Children's Behavioral Problems | ↓ Mental Illness<br>↓ Iron Deficiency<br>↓ Chronic Diseases<br>↑ Life Expectancy<br>↓ Children's Mental Illness<br>↓ Children's Cognitive Problems<br>↓ Children's Behavioral Health Problems<br>↓ Children's Iron Deficiency<br>↓ Children's Oral Health Problems | ↑ Life Expectancy<br>↑ Health Status<br>↑ Mental Health | ↓ Mortality<br>↓ Asthma Prevalence<br>↓ Depression<br>↓ Adverse Birth Outcomes including low birth weight and small for gestational age<br>↑ Life Expectancy |

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

**Table 3-15: Scoping Plan directional benefits for health co-benefit areas (traffic pollution, wildfire, and active transportation)**

| Health Co-benefit Areas* | | | |
|---|---|---|---|
| **Quantitative vs. Qualitative** | **Reduced Traffic Pollution** | **Reduced Wildfire Smoke** | **Increased Active Transportation** |
| **Research was used for Quantitative Analysis** | ↓ Children's Respiratory Outcomes, Hospital Admissions<br>↓ Children's Respiratory Outcomes, Emergency Room Visits<br>↓ Children's Asthma Onset<br>↓ Children's Asthma Symptoms | ↓ All-Cause Mortality<br>↓ Asthma, Hospital Admissions<br>↓ COPD, Hospital Admissions<br>↓ All Respiratory Outcomes, Hospital Admissions<br>↓ Asthma, Emergency Room Visits<br>↓ All Respiratory Outcomes, Emergency Room Visits<br>↓ All Cardiac Outcomes, Emergency Room Visits | ↓ Cardiovascular Diseases<br>↓ Colon Cancer<br>↓ Breast Cancer<br>↓ Diabetes<br>↓ Dementia<br>↓ Lung Cancer<br>↓ Respiratory Disease<br>↓ Depression<br>↑ Traffic Accidents |
| **Research was used for Qualitative Analysis** | ↑ Children's Lung Function Growth<br>↓ Children's Bronchitic Symptoms<br>↓ Children's Impaired Cognitive Development<br>↓ Children's Adverse Birth Outcomes, including low birth weight and preterm birth | | |

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

In summary, the qualitative health analysis of the No-Action versus Take-Action scenarios for this Scoping Plan shows an overwhelming benefit for the state by taking action to move forward to carbon neutrality while continuing efforts to increase health equity and resilience in individual communities. Taking action can improve physical and mental health for adults and children, reduce a range of chronic illnesses, and promote improvements in life expectancy. Development and implementation of actions to achieve the outcomes called for in this Scoping Plan should consider how to engage affected communities in implementation, address the existing health and opportunity gaps, and pursue equitable implementation statewide and locally. This Scoping Plan deployment of clean technology and fuels, together with improved land management, will reduce GHGs and air pollution and create more resilient communities that are better able to prepare for and recover from extreme climate events.

## Environmental Analysis

In May 2022, CARB, as the lead agency for the Scoping Plan, released for public review the Draft Environmental Analysis (Draft EA) for this Scoping Plan; it assessed the potential environmental impacts of implementing the Scoping Plan. CARB circulated the Draft EA for public review and comment for a period of 45 days that began on May 10, 2022, and ended on June 24, 2022. CARB held a public hearing on June 23, 2022 to provide the opportunity for public comment. During the review period, written and oral comments were received on the Draft EA. CARB reviewed the comments to identify environmental topics and began preparation of responses to those comments.

After the end of the Draft EA public review period, CARB identified potential revisions to certain aspects of this Scoping Plan that merit revisions to the project description. This new information results from, among other things, revisions to the project description regarding energy sector goals (including offshore wind), revised carbon removal targets, and additional strategies for natural and working lands. CARB released a Recirculated Draft EA for a written public comment period that started September 9, 2022, and ended on October 24, 2022. See Chapter 2 of the Recirculated Draft EA[290] for further information regarding the changes. The Recirculated Draft EA assesses the potential for significant adverse and beneficial environmental impacts associated with all proposed actions in this Scoping Plan, and provides a programmatic environmental analysis of the reasonably foreseeable compliance responses that could result from implementation of the Scoping

[290] CARB. 2022. Recirculated Draft EA. https://ww2.arb.ca.gov/sites/default/files/2022-09/2022-draft-sp-appendix-b-draft-ea-recirc.pdf.

Plan.[291] The Recirculated Draft EA concluded implementation of this Scoping Plan could result in the following:

- Beneficial impacts to: air quality (long-term operational-related) and GHG emissions (short-term construction-related and long-term operational-related)
- Less than significant impacts to: energy demand, mineral resources, population and housing, public services, recreation (short-term construction-related), and wildfire (short-term construction-related)
- Potentially significant and unavoidable adverse impacts to: aesthetics, agriculture and forest resources, air quality (construction-related and operational odors), biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, recreation (long-term operational-related), transportation and traffic, tribal cultural resources, utilities and service systems, and wildfire (long-term operational-related

Before the public meeting at which the Board will consider this Scoping Plan Update, CARB will publish the Final EA as Appendix B (Final Environmental Analysis) to this Scoping Plan, along with written responses to timely submitted comments raising significant environmental issues received on the Draft EA and the Recirculated Draft EA, which will be presented to the Board for consideration.

[291] The Recirculated Draft EA is available at *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents*.

# Chapter 4: Key Sectors

Chapter 4 provides an overview of the major energy sources and technology in use today, and of alternative clean technology and fuels to support decarbonization based on the latest information available. Every sector of the economy will need to begin to transition in this decade to meet our GHG reduction goals and achieve carbon neutrality no later than 2045. AB 32 requires climate change mitigation policies to be considered in the context of the sector's contribution to the state's total GHG emissions. The transportation, electricity (in-state and imported), and industrial sectors are the largest contributors of GHGs in the state and present the largest opportunities for GHG reductions. Actions to reduce fossil fuel combustion in these sectors also can provide critical air pollution reductions in low-income communities and communities of color, which are often located adjacent to these sources. A carbon neutrality framework also elevates the role of $CO_2$ removal through natural and working lands and mechanical capture and storage. Actions that support energy efficiency, reduced VMT, alternative fuels, and renewable power also can provide benefits by reducing both criteria and toxic air pollutants.

What sets this plan apart from previous Scoping Plans is the focus on the accelerated rate of deployment of clean technology and energy within every sector. As a result, specific actions, including accelerated rates of deployment of clean technology and fuels identified within this Scoping Plan, will need to be translated into both new and amended regulations, policies, and incentive programs. State agencies will need to evaluate current authority to align existing policies or develop new ones to achieve outcomes called for in this Scoping Plan. Legislative support may be needed in some cases to ensure authority and funding is sufficient to ensure this Scoping Plan is translatable to action on the ground. Most regulations, or change to existing regulations, ultimately considered by the Board or other state agencies for adoption will be subject to administrative procedure requirements. Accordingly, they must rely on specific subsequent supporting analysis and extensive public processes and consultations with interested tribes to develop and identify appropriate proposals for effective implementation. For example, any proposal to strengthen the LCFS regulations through amendments increasing the stringency of the carbon intensity (CI) targets would be considered on the basis of a public process, including workshops, and focused environmental, economic, and public health analyses.

Policies that ensure economy-wide investment or program decisions that incorporate consideration of GHG emissions are particularly important. As we pursue GHG reduction targets, we must acknowledge the manner in which built and natural environments are connected, how changes in one may impact the other, and how policy choices in one sector can and do impact other sectors. For example, fostering more compact, transportation-efficient development in infill areas and increasing transportation choices with the goal of reducing VMT not only reduces demand for transportation fuel but also requires less energy for buildings and helps to conserve natural and working lands that sequester carbon. Therefore, the multiple and often interwoven actions that reduce VMT both reduce emissions from the transportation sector and support reductions needed in other sectors.

Legislation, such as SB 350[292] (De León and Leno, Chapter 457, Statutes of 2015), has recognized the need for CARB, the CEC, and the CPUC to work together to ensure the state's energy and climate goals are integrated in procurement decisions by load serving entities as part of Integrated Resource Plans. Moving forward, it is especially critical that similar approaches are adopted to break down silos across state agencies to ensure policies and programs are aligned with multiple state priorities outlined in this plan. Finally, supportive legislative direction, such as SB 905 that requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program, may also benefit emerging areas of policy to provide express agency authority and roles for these nascent efforts, including streamlining of permitting, while ensuring that protections for communities are in place.

Unlike previous Scoping Plans that separated out individual economic sectors, this Scoping Plan approaches decarbonization from two perspectives: (1) managing a phasedown of existing energy sources and technology and (2) ramping up, developing, and deploying alternative clean energy sources and technology over time. This approach supports a more comprehensive consideration of our energy infrastructure, the ability to repurpose existing assets, and the need to build new assets. It also provides multiple metrics beyond just the annual AB 32 GHG Inventory to better enable tracking progress. For example, it clearly demonstrates the production and distribution rates of specific types of clean energy, such as adding 4.3 GW of utility solar and 2.5 GW of storage year-over-year between now and 2035 to be on track to achieve carbon neutrality no later than 2045, and does the same for technology deployment, such as 11 million ZEVs in 2035.

The sections below include key actions to support success in the necessary transition away from fossil combustion, which is an overriding goal of this plan. The wide array of complementary and supporting actions being contemplated or to be undertaken across state government are detailed here. The broad view of actions described in this chapter thus provides context for the specific deployment of clean technology and fuels identified in the Scoping Plan Scenario described in Chapter 2. Actions identified in this Scoping Plan are based on currently known options and the latest science. As part of future Scoping Plan updates, additional clean technology and fuels may be identified and added to the mix of needed tools to continue to reduce the state's GHG emissions, support air quality co-benefits, and remove carbon from the atmosphere.

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[292] California Air Resources Board. SB 350 Electricity Sector Greenhouse Gas Planning Targets. https://ww2.arb.ca.gov/our-work/programs/sb350.

## Transportation Sustainability

The transportation sector has long relied on liquid petroleum fuels as the primary energy source for internal combustion engine (ICE) vehicles, including cars, trucks, locomotives, marine equipment, and aircraft. Combustion of fossil fuels in vehicles emits significant amounts of GHGs, criteria pollutants, and toxic air contaminants. In 2019,[293] the transportation sector accounted for approximately 50 percent of statewide GHG emissions[294] and thus was by far the single largest source of carbon pollution in the state. In addition, the transportation sector accounted for over 80 percent of statewide NOx emissions and 30% of fine particulate matter emissions, including toxic diesel particulate matter.[295]

Communities adjacent to congested roadways, including ports and distribution centers, are exposed to the highest concentration of toxic pollutants from vehicles and equipment consuming fossil fuels, leading to a number of demonstrated health impacts such as respiratory illnesses, higher likelihood of cancer development, and premature death. In addition, communities located near oil extraction operations or crude oil refineries often experience higher exposure to poor air quality. While CARB's programs, along with local action, have made substantial progress over the past few decades, it is clear that California must transition away from fossil fuels to zero-emission technologies with all possible speed and pursue policies that result in less driving, in order to meet our GHG and air quality targets.

The transportation sector can be divided into three general categories: Technology, Fuels, and Vehicle Miles Traveled.

- *Technology* refers to the vehicles themselves, as well as the associated refueling infrastructure for those vehicles.
- *Fuels* refers to the energy source used to power vehicles and the facilities that produce them.
- Vehicle travel is measured as *vehicle miles traveled* (VMT), and is a product of development patterns and available transportation options.

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[293] In 2020 the state experienced shelter-in-place orders in response to the COVID-19 pandemic. The orders, and the effects of the pandemic, led to a significant year-over-year decline in transportation emissions in 2020. This means 2019 is likely a more representative year for overall transportation emissions and 2020 a likely outlier in the historical transportation emissions trend data.
[294] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf. This includes upstream oil extraction and refining emissions.
[295] CARB. California Greenhouse Gas Emission Inventory Program. https://ww2.arb.ca.gov/our-work/programs/ghg-inventory-program.

## Sector Transition

### Technology

Vehicles must transition to zero emission technology to decarbonize the transportation sector. Executive Order N-79-20[296] reflects the urgency of transitioning to zero emission vehicles (ZEVs) by establishing target dates for reaching 100 percent ZEV sales or fleet transitions to ZEV technology. The primary ZEV technologies available today are battery-electric and hydrogen fuel cell electric vehicles (FCEVs), both of which emit zero tailpipe GHGs, criteria pollutants, and toxic air contaminants, as they do not burn fuel. These vehicles are rapidly growing in performance, affordability, and popularity.[297] Plug-in hybrid electric vehicles also offer a limited but increasing range of zero emission operation and will play a role in the transition to ZEVs.

Light-duty passenger vehicles consume the majority of gasoline in the state—12.9 billion gallons in 2019[298]—and are well-suited for transitioning to ZEVs. EO N-79-20 calls for 100 percent ZEV sales of new light-duty vehicles by 2035, and this target is reflected in this Scoping Plan.[299] The Advanced Clean Cars II regulation fulfills the goal in the Executive Order and serves as the primary mechanism to help deploy ZEVs. A number of existing incentive programs also support this transition, including the Clean Cars 4 All Program.[300] Heavy-duty trucks are the largest source of diesel particulate matter, a toxic air contaminant that is directly linked to a number of adverse health impacts, and EO N-79-20 also sets targets for transitioning the medium- and heavy-duty fleet to zero emissions: by 2035 for drayage trucks and by 2045 for buses and heavy-duty long-haul trucks where feasible. Replacing heavy-duty vehicles with ZEV technology will significantly reduce GHG emissions and diesel PM emissions in low-income communities and communities of color adjacent to ports, distribution centers, and highways. The existing Advanced Clean Trucks regulation, paired with the proposed Advanced Clean Fleets regulation, are designed to transition a significant amount of the

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[296] Executive Department. State of California. Executive Order N-79-20. https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.

[297] CARB. 2021. Public Workshop for Advanced Clean Cars II. May 6. https://ww2.arb.ca.gov/sites/default/files/2021-05/acc2_workshop_slides_may062021_ac.pdf.

[298] CARB. 2022. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/fuel_activity_inventory_by_sector_all_00-20.xlsx.

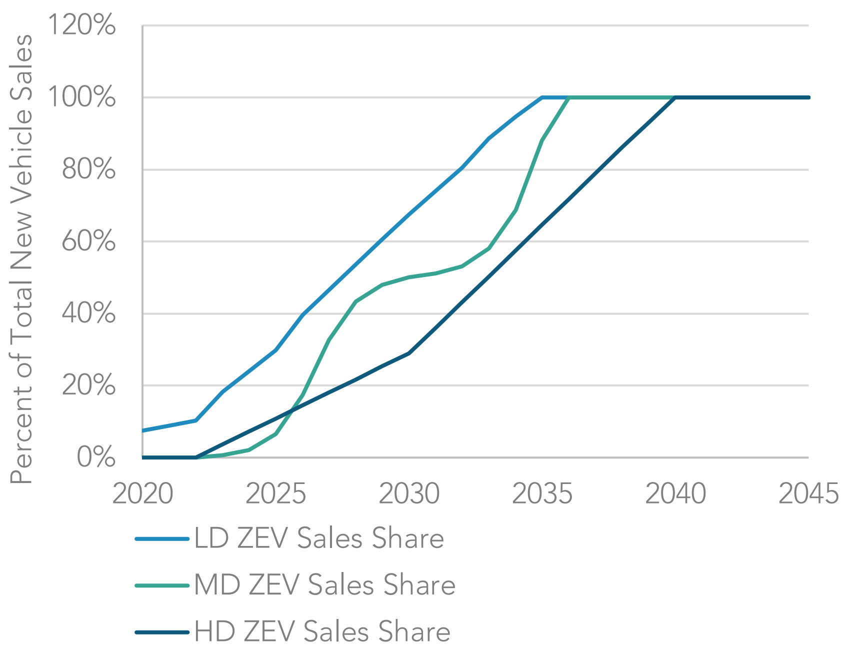
[299] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A, with reference to the date at which all new vehicle sales are ZEVs. finalejacrecs.pdf (arb.ca.gov).

[300] CARB. Clean Cars 4 All. https://ww2.arb.ca.gov/our-work/programs/clean-cars-4-all. The Clean Vehicle Rebate Project (CVRP) also supports the transition to ZEVs. https://cleanvehiclerebate.org/en.

California truck fleet to ZEV technology. As with the LDV sector, a number of incentive programs support this transition, such as the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP).[301]

Figure 4-1 below illustrates the pace of transition in vehicle technology needed to drastically reduce GHG emissions from vehicles. All vehicle classes reach 100 percent ZEV sales before 2045, with some achieving this well before. The ZEV technology across the vehicle classes is assumed to be primarily battery electric and hydrogen fuel cell (reflecting the primary ZEV technologies available today).[302]

**Figure 4-1: Transition of on-road vehicle sales to ZEV technology in the Scoping Plan Scenario**




Today, off-road vehicles also rely heavily on ICE technology. Executive Order N-79-20 sets an off-road equipment target of transitioning the entire fleet to ZEV technology by 2035, where feasible. There is a great need for both investment and innovation in the off-road space in order to develop and commercialize zero emission equipment types that meet or exceed the performance of existing equipment. A number of funding sources currently support this transition, including programs such as FARMER, Carl Moyer, and

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[301] California HVIP. Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project. https://californiahvip.org/?msclkid=efaf65f2c26f11eca6bdd08ecc323864.

[302] The light-duty fleet includes more than 11 million battery electric and hydrogen fuel cell vehicles in 2035 and over 23 million battery electric and hydrogen fuel cell vehicles in 2045.

the Community Air Protection Incentives—as well as Low Carbon Transportation Incentives, including the Clean Off-Road Equipment (CORE) program. In addition, the 2021–22 California budget provided record-high allocations for funding ZEVs, including off-road equipment, and the 2022–23 budget is similarly ambitious.[303] Several regulations focused on transitioning to zero emission off-road equipment have recently been adopted or are in the works, and apply to locomotives,[304] forklifts, ocean-going vessels at berth,[305] commercial harbor craft,[306] small off-road engines,[307] and more.

Intrastate aviation relies on ICE technology today, but battery-electric and hydrogen fuel cell aviation applications are in development, along with sustainable aviation fuel. The Scoping Plan Scenario includes a transition of 20% of aviation fuel demand to ZEV technologies by 2045 and sustainable aviation fuel for the rest.

Refueling infrastructure is a crucial component of transforming transportation technology. Electric vehicle chargers and hydrogen refueling stations must become easily accessible for all drivers to support a wholesale transition to ZEV technology. Deployment of ZEV refueling infrastructure is currently supported by a number of existing local and state public funding mechanisms, the new National Electric Vehicle Infrastructure (NEVI) federal funding mechanism, California's electric utilities, the Electrify America initiative that was established in response the Volkswagen ZEV commitment, and by numerous companies, such as EVgo, ChargePoint, Tesla, Ford, FirstElement Fuel, Chevron, Shell, and Iwatani, who are investing substantial private resources into developing these networks. Private investment in reliable, affordable and ubiquitous refueling infrastructure must drive the transition as the business case for ZEVs continues to strengthen.

**Strategies for Achieving Success**

- Achieve 100 percent ZEV sales of light-duty vehicles by 2035[308] and medium-heavy-duty vehicles by 2040.
- Achieve a 20% zero emission target for the aviation sector.

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[303] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. CARB and the Administration are committed to increasing focus on transportation equity investment as was reflected in the governor's 2022–23 budget. *finalejacrecs.pdf (arb.ca.gov)*.
[304] CARB. Reducing Rail Emissions in California. *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california.*
[305] CARB. Ocean-Going Vessels At Berth Regulation. *https://ww2.arb.ca.gov/our-work/programs/ocean-going-vessels-berth-regulation*.
[306] CARB. CARB passes amendments to commercial harbor craft regulation. *https://ww2.arb.ca.gov/news/carb-passes-amendments-commercial-harbor-craft-regulation*.
[307] CARB. Small Off-Road Engines (SORE). *https://ww2.arb.ca.gov/our-work/programs/small-off-road-engines-sore*.
[308] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A. *finalejacrecs.pdf (arb.ca.gov)*.

- Develop a rapid and robust network of ZEV refueling infrastructure to support the needed transition to ZEVs.
- Ensure that the transition to ZEV technology is affordable for low-income households and communities of color, and meets the needs of communities and small businesses.[309]
- Prioritize incentive funding for heavy-duty ZEV technology deployment in regions of the state with the highest concentrations of harmful criteria and toxic air contaminant emissions.[310]
- Promote private investment in the transition to ZEV technology, undergirded by regulatory certainty such as infrastructure credits in the Low Carbon Fuel Standard for hydrogen and electricity[311] and hydrogen station grants from the CEC's Clean Transportation Program[312] pursuant to Executive Order B-48-18.[313]
- Evaluate and continue to offer incentives similar to those through FARMER,[314] Carl Moyer,[315] the Clean Fuel Reward Program,[316] the Community Air Protection Program,[317] and Low Carbon Transportation,[318] including CORE.[319] Where feasible, prioritize and increase funding for clean transportation equity programs.[320]
- Continue and accelerate funding support for zero emission vehicles and refueling infrastructure through 2030 to ensure the rapid transformation of the transportation sector.

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[309] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF6, in the context of communities. *finalejacrecs.pdf (arb.ca.gov)*.
[310] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF7. *finalejacrecs.pdf (arb.ca.gov)*.
[311] CARB. LCFS ZEV Infrastructure Crediting. *https://ww2.arb.ca.gov/resources/documents/lcfs-zev-infrastructure-crediting*.
[312] CEC. Clean Transportation Program. *https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program*.
[313] EO B-48-18 calls for 200 hydrogen refueling stations by 2025. *https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf*.
[314] CARB. FARMER program. *https://ww2.arb.ca.gov/our-work/programs/farmer-program*.
[315] CARB. Carl Moyer program. *https://ww2.arb.ca.gov/our-work/programs/carl-moyer-memorial-air-quality-standards-attainment-program*.
[316] California Clean Fuel Reward Program. *https://cleanfuelreward.com/*.
[317] CARB. Community Air Protection Program. *https://ww2.arb.ca.gov/capp*.
[318] CARB. Low Carbon Transportation Investments and Air Quality Improvement Program. *https://ww2.arb.ca.gov/our-work/programs/low-carbon-transportation-investments-and-air-quality-improvement-program*.
[319] Clean Off-Road Equipment (CORE) Voucher Incentive Program. *https://californiacore.org/*.
[320] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. *finalejacrecs.pdf (arb.ca.gov)*.

- Evaluate and align with this Scoping Plan relevant CARB policies such as Advanced Clean Cars II,[321] Innovative Clean Transit,[322] Zero Emission Airport Shuttle,[323] California Phase 2 GHG Standards,[324] Advanced Clean Trucks, Advanced Clean Fleets, Zero Emission Forklifts,[325] In-use Locomotives,[326] the Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, In-use Off-Road Diesel-Fueled Fleets Regulation,[327] Commercial Harbor Craft,[328] Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, Amendments to the In-use Off-Road Diesel-Fueled Fleets Regulation,[329] carbon pricing through the Cap-and-Trade Program,[330] and the Low Carbon Fuel Standard.[331]
- Identify and address permitting and market barriers to successful rapid ZEV technology deployment while protecting public health and the environment.

## Fuels

Transitioning away from conventional ICE vehicles is part of the solution, but we must ensure that an adequate supply of zero-carbon alternative fuel and distribution is available to power these vehicles. Electricity and hydrogen are currently the primary fuels for ZEVs,

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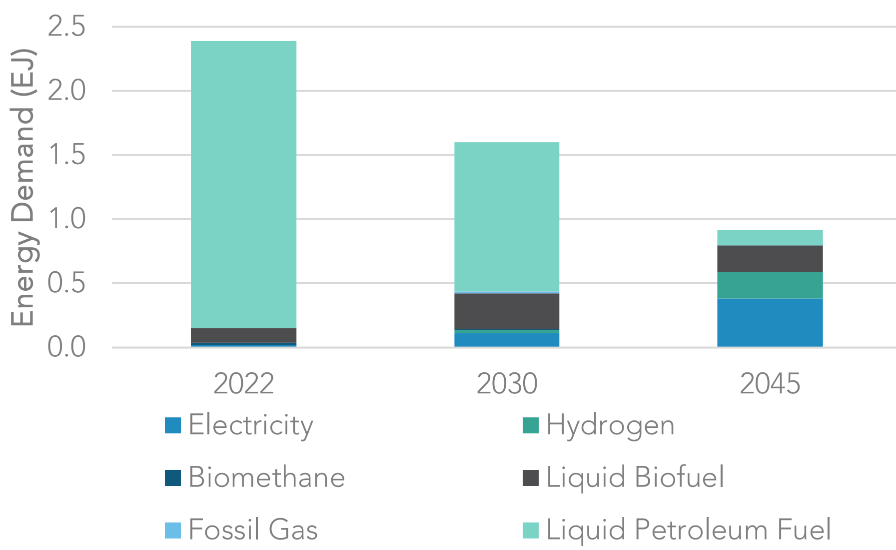
[321] CARB. Advanced Clean Cars Program. https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program. Cal. Code Regs., tit. 13, §§ 1900, 1961.2, 1961.3, 1961.4, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, 2317, 2903.
[322] CARB. Innovative Clean Transit. https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit. Cal. Code Regs., tit. 13, §§ 2023—2023.11.
[323] CARB. Zero-Emission Airport Shuttle. https://ww2.arb.ca.gov/our-work/programs/zero-emission-airport-shuttle. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[324] CARB. California Phase 2 Greenhouse Gas Standards. https://ww2.arb.ca.gov/our-work/programs/greenhouse-gas-standards-medium-and-heavy-duty-engines-and-vehicles/phase2. Cal. Code Regs., tit. 13, §§ 1956.8 and 2036; and Cal. Code Regs., tit. 17, §§ 95301, 95302, 95303, and 95663.
[325] CARB. Zero-Emission Forklifts. https://ww2.arb.ca.gov/our-work/programs/zero-emission-forklifts. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[326] CARB. Reducing Rail Emissions. https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california. Proposed Cal. Code Regs., tit. 13, §§ 2478—2478.16.
[327] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation. Cal. Code Regs., tit. 13, §§ 2449, 2449.1, 2449.2.
[328] CARB. Commercial Harbor Craft. https://ww2.arb.ca.gov/our-work/programs/commercial-harbor-craft. Cal. Code Regs., tit. 13, § 2299.5.
[329] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation.
[330] CARB. Cap-and-Trade Program. https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program. Cal. Code Regs., tit. 17, §§ 95801 et seq.
[331] CARB. Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard. Cal. Code Regs., tit. 17, §§ 95480 et seq.

and both fuels must be produced using low-carbon technology and feedstocks to minimize upstream emissions.

The transition to complete ZEV technology will not happen overnight. Conventional ICE vehicles from legacy fleets will remain on the road for some time, even after all new vehicle sales have transitioned to ZEV technology. In addition, some equipment types are only now in the initial stages of development of ZEV technology for propulsion, such as commercial aircraft or ocean-going vessels. In addition to building the production and distribution infrastructure for zero-carbon fuels, the state must continue to support low-carbon liquid fuels during this period of transition and for much harder sectors for ZEV technology such as aviation, locomotives, and marine applications. Biomethane currently displaces fossil fuels in transportation and will largely be needed for hard-to-decarbonize sectors but will likely continue to play a targeted role in some fleets while the transportation sector transitions to ZEVs. Figure 4-2 provides the detail on fuels used in 2020 and the fuel mix under the Scoping Plan Scenario for 2035 and 2045.

**Figure 4-2: Transportation fuel mix in 2022, 2030, and 2045 in the Scoping Plan Scenario[332]**




Private investment in alternative fuels will play a key role in diversifying the transportation fuel supply away from fossil fuels. The Low Carbon Fuel Standard is the primary mechanism for transforming California's transportation fuel pool with low-carbon

[332] See https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx for transportation fuels by year.

alternatives and has fostered a growing alternative fuel market. Partially as a result of the powerful market signals from the LCFS, fuels like renewable diesel, sustainable aviation fuel, biomethane, and electricity have all gained significant market shares and continue to displace gasoline and diesel in both on- and off-road vehicles. In addition, Executive Order N-79-20 calls on state agencies to support the transition of existing fuel production facilities away from fossil fuels and directs that this transition also protect and support workers, public health, safety, and the environment. In line with this direction, existing refineries could be repurposed to produce sustainable aviation fuel, renewable diesel, and hydrogen. This trend has already begun, and continuing to develop fuel production capacity in-state to support the energy transition while making the most efficient use of existing assets is critical to avoiding emissions leakage. If fuel demand persists after fuel production facilities have ceased operations, fuel demand will have to be met through imports.

As we transition or build new energy production facilities and infrastructure, it will be important to ensure low-income communities, tribes, and communities of color do not experience increases in existing air pollution disparities and continue to experience a reduction in the air pollution disparities that exist today. California must use the best available science to ensure that raw materials used to produce transportation fuels do not incentivize feedstocks with little to no GHG reductions from a life cycle perspective. A dramatic increase in alternative fuel production must not come at the expense of global deforestation, unsustainable land conversion, or adverse food supply impacts, to name a few examples. CARB will continue to monitor scientific findings on these topics to ensure that California policies, such as the LCFS, send the appropriate market signals and do not result in unintended consequences.[333]

**Strategies for Achieving Success**

- Accelerate the reduction and replacement of fossil fuel production and consumption in California.[334]
- Incentivize private investment in new zero-carbon fuel production in California.
- Incentivize the transition of existing fuel production and distribution assets to support deployment of low- and zero-carbon fuels while protecting public health and the environment.
- Invest in the infrastructure to support reliable refueling for transportation such as electricity and hydrogen refueling.

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[333] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).
[334] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F3. finalejacrecs.pdf (arb.ca.gov).

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Initiate a public process focused on options to increase the stringency and scope of the LCFS:
    - Evaluate and propose accelerated carbon intensity targets pre-2030 for LCFS.
    - Evaluate and propose further declines in LCFS post-2030 carbon intensity targets to align with this 2022 Scoping Plan.
    - Consider integrating opt-in sectors into the program.
    - Provide capacity credits for hydrogen and electricity for heavy-duty fueling.
- Monitor for and ensure that raw materials used to produce low-carbon fuels or technologies do not result in unintended consequences.[335]

## Vehicle Miles Traveled

Transforming the transportation sector goes beyond phasing out combustion technology and producing cleaner fuels. Managing total demand for transportation energy by reducing the miles people need to drive on a daily basis is also critical as the state aims for a sustainable transportation sector in a carbon neutral economy. Though GHG emissions are declining due to cleaner vehicles and fuels, rising VMT can offset the effective benefits of adopted regulations.

Even under full implementation of Executive Order N-79-20 and CARB's Advanced Clean Cars II Regulations, with 100 percent ZEV sales in the light-duty vehicle sector by 2035, a significant portion of passenger vehicles will still rely on ICE technology, as demonstrated in Figure 4-2 above. Accordingly, VMT reductions will play an indispensable role in reducing overall transportation energy demand and achieving the state's climate, air quality, and equity goals. After a significant pandemic-induced reduction in VMT during 2020, passenger VMT has steadily climbed back up and is now closing in on pre-pandemic levels.[336] Driving alone with no passengers remains the primary mode of travel in California, amounting to 75 percent of the mode share for daily commute trips. Conversely, the transit industry, which was significantly impacted during

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[335] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).

[336] U.S. Department of Transportation. 2021. December 2021 Traffic Volume Trends. Figure 3 - Seasonally Adjusted Vehicle Miles Traveled by Month. https://www.fhwa.dot.gov/policyinformation/travel_monitoring/21dectvt/figure3.cfm.

the lockdown months, and has struggled to recover; ridership only averages two-thirds of pre-pandemic levels,[337] [338] and service levels also lag behind.

Sustained VMT reductions have been difficult to achieve for much of the past decade, in large part due to entrenched transportation, land use, and housing policies and practices. Specifically, historic decision-making favoring single-occupancy vehicle travel has shaped development patterns and transportation policy, generating further growth in driving (and making transit, biking and walking less viable alternatives). These policies have also reinforced long-standing racial and economic injustices that leave people with little choice but to spend significant time and money commuting long distances, placing a disproportionate burden on low-income Californians, who pay the highest proportion of their wages on housing and transportation. While CARB has included VMT reduction targets and strategies in the Scoping Plan and appendices, these targets are not regulatory requirements, but would inform future planning processes. CARB is not setting regulatory limits on VMT in the 2022 Scoping Plan; the authority to reduce VMT largely lies with state, regional, and local transportation, land use, and housing agencies, along with the Legislature and its budgeting choices.

Appendix E (Sustainable and Equitable Communities) elaborates on reasons for reducing VMT and identifies a series of policies that, if implemented by various responsible authorities, could help to achieve the recommended VMT reduction trajectory included in this Scoping Plan (and related mode share increases for transit and active transportation). These policies aim to advance four strategic objectives:

1. Align current and future funding for transportation infrastructure with the state's climate goals, preventing new state-funded projects from inducing significant VMT growth and supporting an ambitious expansion of transit service and other multimodal alternatives.
2. Move funding for transportation beyond the gasoline and diesel taxes and implement fuel-agnostic pricing strategies that accomplish more productive uses of the roadway network and generate revenues to further improve transit and other multimodal alternatives.
3. Deploy autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
4. Encourage future housing production and multi-use development in infill locations and other areas in ways that make future trip origins and destinations

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[337] U.S. Government Accountability Office. January 25, 2022. During COVID-19, Road Fatalities Increased and Transit Ridership Dipped. https://www.gao.gov/blog/during-covid-19-road-fatalities-increased-and-transit-ridership-dipped.
[338] American Public Transportation Association. APTA - Ridership Trends. https://transitapp.com/APTA.

closer together and create more viable environments for transit, walking, and biking.

The pace of change to reduce VMT must be accelerated. Certainly, structural reform will be challenging, but California has demonstrated time and again that it possesses the collective leadership and commitment to break away from ideas that no longer represent Californians' values and their aspirations for the many generations to come.

**Strategies for Achieving Success**

- Achieve a per capita VMT reduction of at least 25 percent below 2019 levels by 2030 and 30 percent below 2019 levels by 2045. [339]
- Reimagine new roadway projects that decrease VMT in a way that meets community needs and reduces the need to drive.
- Invest in making public transit a viable alternative to driving by increasing affordability, reliability, coverage, service frequency, and consumer experience.[340]
- Implement equitable roadway pricing strategies based on local context and need, reallocating revenues to improve transit, bicycling, and other sustainable transportation choices.[341]
- Expand and complete planned networks of high-quality active transportation infrastructure.[342]
- Channel the deployment of autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
- Streamline access to public transportation through programs such as the California Integrated Travel Project.
- Ensure alignment of land use, housing, transportation, and conservation planning in adopted regional plans, such as regional transportation plans (RTP)/ sustainable communities strategies (SCS), regional housing needs assessments (RHNA), and local plans (e.g., general plans, zoning, and local transportation plans), and develop tools to support implementation of these plans.

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[339] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[340] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[341] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[342] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1F. *finalejacrecs.pdf (arb.ca.gov)*.

- Accelerate infill development and housing production at all affordability levels in transportation-efficient places, with a focus on housing for lower-income residents.

## Clean Electricity Grid

Much of the state's success to date in reducing GHGs is due to decarbonization of the electricity sector as a result of the RPS, SB 100 implementation, and the Cap-and-Trade Program. Moving forward, a clean, affordable, and reliable electricity grid will serve as a backbone to support deep decarbonization across California's economy. Under this Scoping Plan, the role of electricity in powering the economy will grow in almost every sector.

In 2021, 70 percent of California electricity demand was served by in-state power plants totaling about 82 GW, with the rest coming from out-of-state imports.[343] Additionally, approximately 8 GW of customer solar photovoltaic capacity has been installed to date to help with in-state demand.[344] Figure 4-3 shows the breakdown of in-state and imported sources of electricity.

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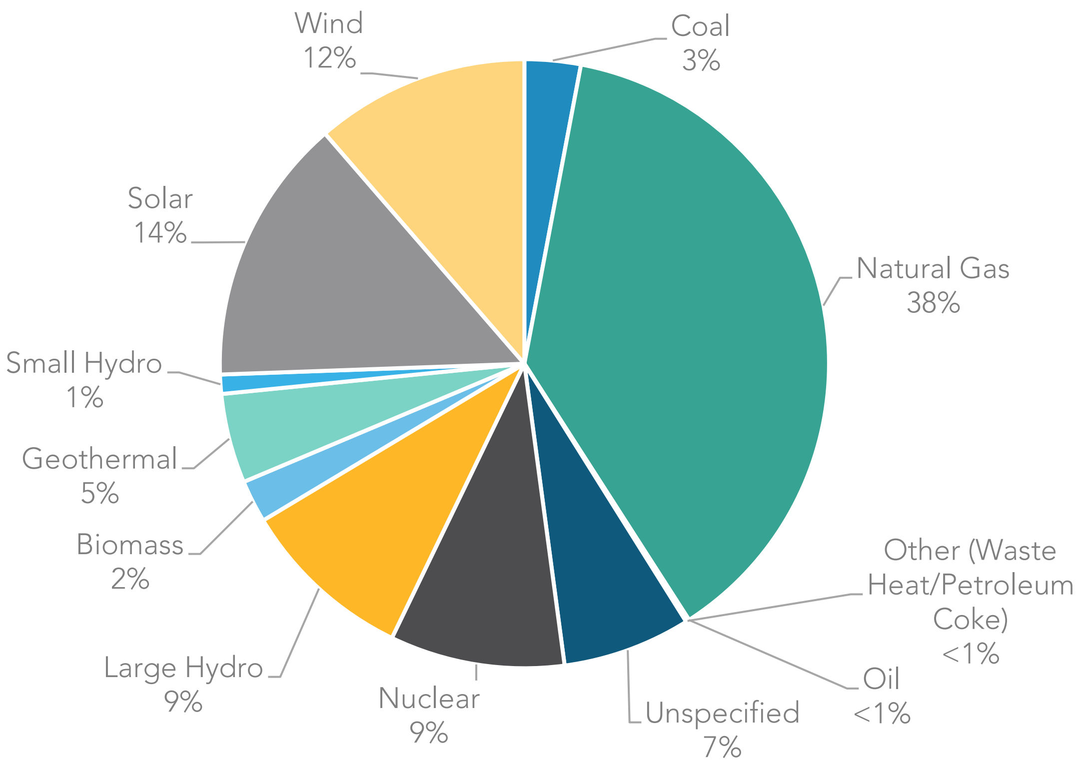
[343] CEC. 2021. Electric Generation Capacity and Energy. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy and CEC. 2021. Total System Electric Generation. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation. Capacity values are nameplate capacity from sources 1 MW and larger.

[344] CEC. 2021. *SB 100 Joint Agency Report Summary: Achieving 100% Clean Electricity in California, An Initial Assessment.* 10. https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity.

**Figure 4-3: 2021 total system electric generation (based on GWh)[345]**




*Note: Imports contributing to total system generation are comprised of 58% zero-carbon energy and 42% non-renewable and unspecified energy. Percentages do not add to exactly 100 due to rounding.*

In 2021, about 48 percent of electricity generation serving California came from non-renewable and unspecified[346] resources, while 52 percent came from renewable and zero-carbon resources. The state's Strategic Reliability Reserve, established in AB 205 to provide additional reliability insurance during extreme events, may make three of the fossil gas-fired OTC plants planned for retirement available to support the grid on a limited basis after 2023. The state also adopted legislation to facilitate extension of the Diablo Canyon Nuclear Power Plant for five years beyond its 2025 planned closure.[347] At the

[345] *Total system generation* is the sum of all utility-scale, in-state generation, plus net electricity imports. CEC. 2021 Total System Electricity Generation. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation.

[346] *Unspecified power* refers to electricity that is not traceable to a specific generating facility, such as electricity traded through open market transactions. It typically consists of a mix of resources and may include renewables.

[347] In accordance with SB 846 (Dodd, Chapter 239, Statutes of 2022).

same time, the state continues to rapidly expand deployment of clean energy generation and storage resources and plan for increased electrification.[348] This is critical to reducing GHG emissions and addressing the long-term impacts of climate change.

Climate change is causing unprecedented stress on California's energy system—driving high demand and constraining supply. Heat, drought, and wildfires can both reduce electricity supply from reductions in hydropower generation and impacts on generation and transmission performance, and increase demand, especially in the evening hours when solar generation is declining.

California has experienced three straight years of energy reliability challenges, including a multi-day extreme heat event across the western United States with temperatures up to 20 degrees above normal in California, resulting in rotating outages in August 2020. In 2021, heat waves in June prompted a Grid Warning and the onset of emergency conditions, and the Bootleg Fire caused the loss of one transmission line, reducing import capability by 3,000 megawatts into the California Independent System Operator (CAISO) balancing authority area. And from August 31–September 9, 2022, a 10-day extreme heat event resulted in an unprecedented, sustained period of high peak loads in the CAISO system, averaging 47,000 MW and maxing at an all-time record of over 52,000 MW on September 6. The Western region also hit its record peak load on September 6, at 167.5 GW.

Reliable electricity service was maintained throughout the 10-day September 2022 heat wave in spite of the record breaking load levels. Factors that contributed to this outcome include the installation of over 3,500 MW of lithium-ion battery storage since summer 2020, enhanced coordination and communication within and outside of California, engagement with customer groups and other stakeholders, state actions to reduce load during critical times, and the additional capacity provided through the Strategic Reliability Reserve and other new state programs authorized in the 2022 Budget to provide load reduction and support the grid in extreme events. CEC, CPUC, CAISO, and the California Department of Water Resources will continue to build out strategies to enhance reliability in light of the increasing and compounding impacts of climate change on the electricity system.

[348] In June 2021, the CPUC adopted D.21-06-035 directing procurement of 11,500 MW of new capacity between 2023 and 2026 to ensure systemwide electric reliability as Diablo Canyon and several OTC facilities retire. It requires that, out of the 11,500 MW, 2,500 MW must be from zero-emission resources. Additionally, 2,000 MW must be long lead-time resources, with at least 1,000 MW of long-duration storage and 1,000 MW of firm capacity with zero on-site emissions or that qualifies under the RPS eligibility requirements.

While the electricity sector is using less fossil fuel due to increasing amounts of renewables,[349] existing fossil gas generation will continue to play a critical role in grid reliability until other clean, dispatchable alternatives can be deployed at scale. The integration of greater amounts of variable renewable generation resources[350] is changing power system planning and operations, and system operators need resources with flexible attributes to balance shifting supply and demand.

High levels of solar generation can lead to instances of oversupply during the middle of the day, when the sun is brightest.[351] In the evening hours, as the sun is setting, solar generation declines to zero and customers with solar generation shift back to the electric grid. In hot weather, customer demand remains high well into the summer evening period to power air conditioning, which can lead to reliability challenges.[352]

Figure 4-4 shows the energy sources used throughout one summer day in July. Renewable energy is consistent during the middle of the day, but it cannot meet all of the evening demand in the gray area. As illustrated in the figure, fossil gas generation is currently a resource that is typically ramped up to meet this evening demand as solar production begins to drop and electrical loads increase To help address this challenge, resource installations that pair solar with batteries, as well as a greater amount of battery build-out, are coming online currently and over the next five years. Nevertheless, the state's electricity grid is expected to be stressed further in the coming years by heat waves, drought, wildfires, and the growing intermittent power supply from renewables. California must accelerate deployment of diverse clean energy resources to maintain reliability and affordability in the face of climate change.

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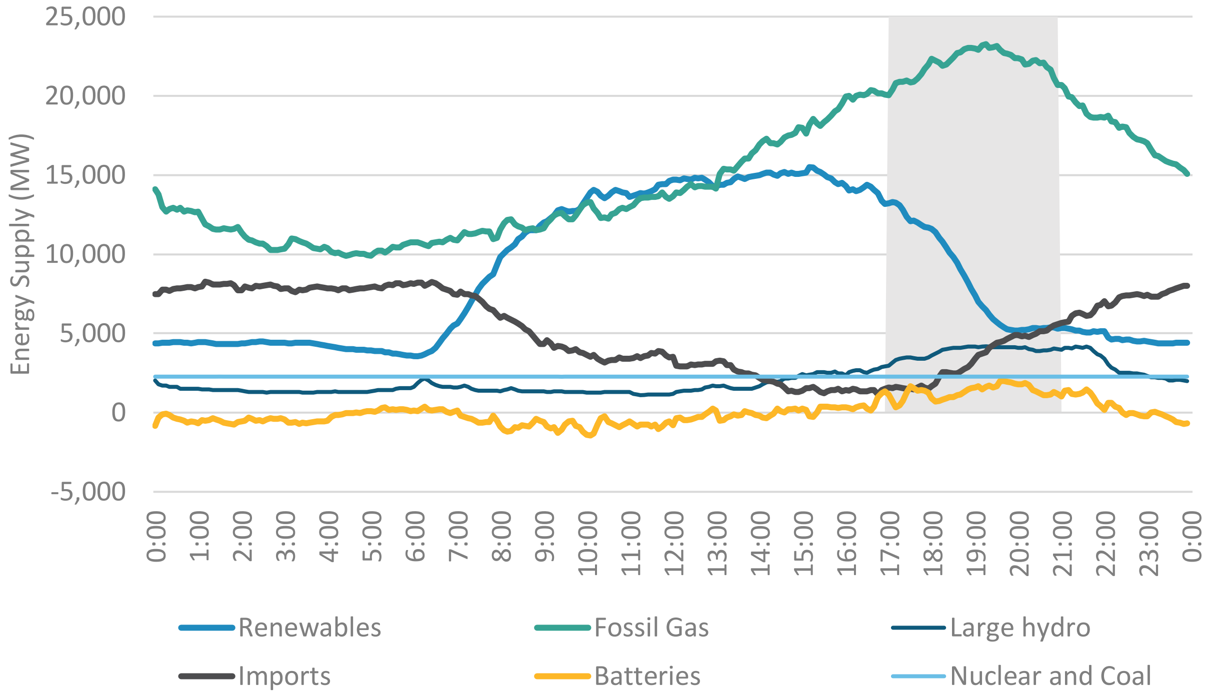
[349] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[350] A *variable renewable generation resource* is a renewable source of electricity that is non-dispatchable due to its fluctuating nature and only produces electricity when weather conditions are right, such as when the sun is shining or the wind is blowing. Renewable resources that can be controlled and are dispatchable include geothermal, biomass, and dam-based hydroelectric power.

[351] *Brightness* is used colloquially here; solar energy depends on insolation (e.g., sun-hours), which is the measurement of cumulative solar energy that reaches an area over a period of time.

[352] CAISO, CPUC, and CEC. 2021. *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave.* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

**Figure 4-4: Electricity supply trend by resource for a California summer day, July 2022**




## Sector Transition

Decarbonizing the electricity sector is a crucial pillar of this Scoping Plan. It depends on both using energy more efficiently and replacing fossil-fueled generation with renewable and zero carbon resources, including solar, wind, energy storage,[353] geothermal, biomass, and hydroelectric power. The RPS Program[354] and the Cap-and-Trade Program continue to incentivize dispatch of renewables over fossil generation to serve state demand. SB 100 increased RPS stringency to require 60 percent renewables by 2030 and for California to provide 100 percent of its retail sales[355] of electricity from renewable and zero-carbon resources by 2045. Furthermore, SB 1020 has added interim targets to

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[353] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. [finalejacrecs.pdf (arb.ca.gov)](finalejacrecs.pdf (arb.ca.gov)).

[354] The CEC estimates that 36 percent of California's 2019 retail electricity sales was served by RPS-eligible renewable resources (see CPUC. 2021. CPUC Perspectives on Electric Sector Decarbonization. *https://ww2.arb.ca.gov/sites/default/files/2021-11/CPUC-sp22-electricity-ws-11-02-21.pdf*).

[355] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* interprets this to mean that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

SB 100’s policy framework to require renewable and zero-carbon resources to supply 90 percent of all retail electricity sales by 2035 and 95 percent of all electricity retail sales by 2040; the governor has asked the CEC to establish a planning goal of at least 20 GW of offshore wind by 2045; and the governor directed that state agencies plan for an energy transition that avoids the need for new fossil gas capacity to meet California’s long-term energy goals.[356] In addition to grid-level resources, state efforts have supported rapid growth of the distributed solar industry through key actions like the California Solar Initiative (SB 1, Murray, Chapter 132, Statues of 2006).[357] Steps to commercialize microgrids powered by clean resources[358] are also being examined as part of SB 1339 (Stern, Chapter 566, Statutes of 2018).[359]

California also continues to advance its appliance and building energy efficiency standards to reduce growth in electricity consumption and meet the SB 350 goal to double statewide energy efficiency savings in electricity and fossil gas end uses[360] by 2030. In 2018, the CEC adopted a building energy efficiency code requiring most new homes to have solar photovoltaic systems[361] (or be powered by a solar array nearby) starting January 1, 2020. In 2019, California reached the milestone of 1 million solar rooftop installations.

Increased transportation and building electrification and continued policy commitment to behind-the-meter solar and storage will continue to drive growth of microgrids and other distributed energy resources (DER).[362] The CPUC’s High-DER proceeding is examining how to prepare the electric grid for a high DER future by determining how to integrate

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[356] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.
[357] More information on the program, which closed in 2016, can be found on the CPUC website, including annual program assessment reports, at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/california-solar-initiative.
[358] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, In part (NF2, NF13). finalejacrecs.pdf (arb.ca.gov).
[359] CPUC. Resiliency and Microgrids. https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids.
[360] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, ES1. finalejacrecs.pdf (arb.ca.gov).
[361] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2. finalejacrecs.pdf (arb.ca.gov).
[362] Distributed energy resources include rooftop solar and other distributed renewable generation resources, energy storage, electric vehicles, time variant and dynamic electric rates, flexible load management, demand response, and energy efficiency technologies.

millions of DERs within the distribution grid to maximize societal and ratepayer benefits from DERs while ensuring grid reliability and affordable rates.[363]

SB 350 also aims to connect long-term planning for electricity needs with the state's climate targets. This is primarily accomplished through CARB's establishment of 2030 GHG emissions targets for the electricity sector in general and for each electricity provider, which inform the CPUC and publicly owned utilities' integrated resource planning. A GHG planning target range of 30 to 53 $MMTCO_2e$—informed by the 2017 Scoping Plan—was originally developed and adopted by CARB in 2018. In its 2021 IRP planning cycle, the CPUC adopted a 38 MMT GHG target for the electricity sector in 2030, which drops to 35 MMT in 2032.[364]

The Scoping Plan Scenario incorporates SB 350's energy efficiency doubling goal, aligns with the CPUC's IRP 2030 GHG target and latest GHG emissions benchmarks through 2035,[365] the governor's 20 GW offshore wind and no new gas generation[366] goals, and SB 100's 2030 RPS and 2045 zero-carbon retail sales targets to reduce dependence on fossil fuels in the electricity sector by transitioning substantial energy demand to renewable and zero-carbon resources.[367] As described in Chapter 2, CCS is applied in limited sectors, including on 16.7 MMT of $CO_2$ from existing fossil gas electricity generation in 2045, to ensure the state achieves the 85 percent reduction in anthropogenic emissions required by AB 1279. Continued transition to renewable and

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[363] The High-DER proceeding is one of four "anchor" proceedings in the CPUC's DER Action Plan 2.0 and is within the Action Plan's infrastructure track. Information on the High-DER proceeding is available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning. The Action Plan can be accessed at: https://www.cpuc.ca.gov/about-cpuc/divisions/energy-division/der-action-plan.

[364] The February 10, 2022, Decision 22-02-004 by the CPUC adopts the 2021 Preferred System Plan, completing the 2019–21 IRP cycle. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF. The Decision requires load serving entities to submit plans in the next IRP cycle detailing how they will meet their proportionate share of a 30 MMT electric sector target, as well as a 38 MMT GHG target.

[365] June 15, 2022, Administrative Law Judge's Ruling for 2022 integrated resource plan filings specifies the need for GHG targets to plan for in 2035 to continue progress toward the 2045 goal. The ruling proposes a straight-line projection from the GHG planning target for 2030. Corresponding to the adopted Preferred System Plan in D.22-02-004, 38 MMT in 2030 leads to a target of 30 MMT in 2035. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M485/K625/485625915.PDF.

[366] The governor's July 22, 2022, letter specifies no new gas generation but does not place any constraints on existing gas resources. Therefore, for purposes of RESOLVE electricity sector modeling, existing gas capacity is an available resource that is able to be reduced over time based on announced retirements or if selected for retirement by the model.

[367] CARB. 2021. PATHWAYS Scenario Modeling: 2022 Scoping Plan Update – Attachment B: Generation Technologies to be included in Modeling. https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf.

zero-carbon electricity resources will enable electricity to become a zero-carbon substitute for fossil fuels across the economy.

Figure 4-5 shows the modeled resource capacity to meet the SB 100 retail sales target.[368] Energy efficiency moderates some of the need for additional electricity generation. However, that is quickly surpassed by growing electricity demand of 26 percent by 2030 and 76 percent by 2045 compared to today (2022) from increased population and electrification of other sectors, as shown in Figure 4-6. The estimated resource build needed to meet this level of demand amounts to approximately 72 GW of utility solar[369] and 37 GW of battery storage by 2045. Annual build rates (over the 2022–2035 period) for the Scoping Plan Scenario will need to increase by about 60 percent and over 700 percent for utility solar and battery storage, respectively, compared to historic maximum rates.[370] To reach the 2045 target, the state will need to quadruple its current level of wind and solar capacity. This does not include capacity associated with hydrogen production nor mechanical CDR, which was modeled off-grid; assuming hydrogen production via electrolysis, this would roughly be equivalent to an additional 10 GW[371] of solar generation needed in 2045, and an additional 64 GW of solar generation for direct air capture in 2045. The scale of solar and battery build rates needed could be reduced through the commercialization of new zero-carbon technologies.

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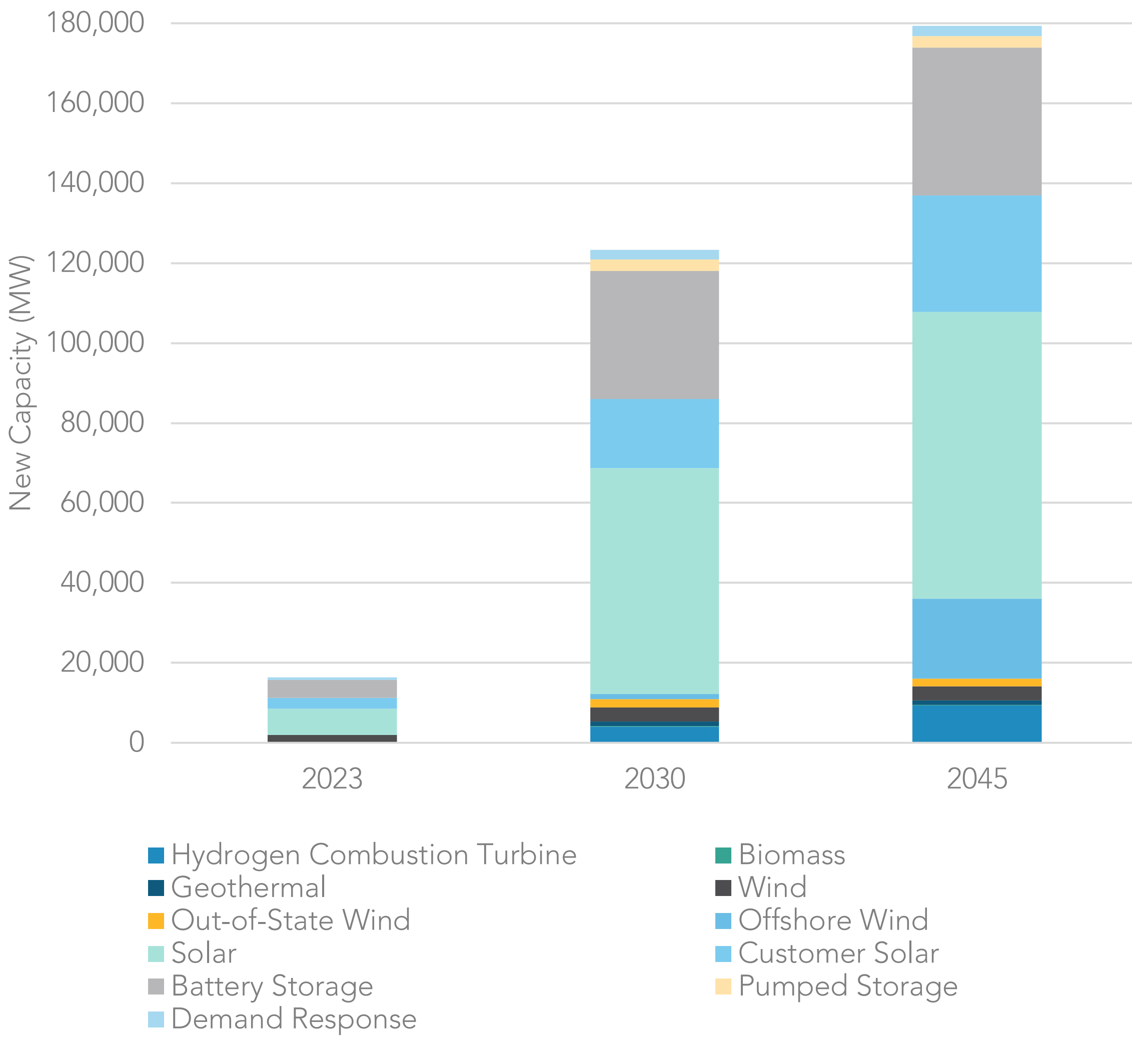
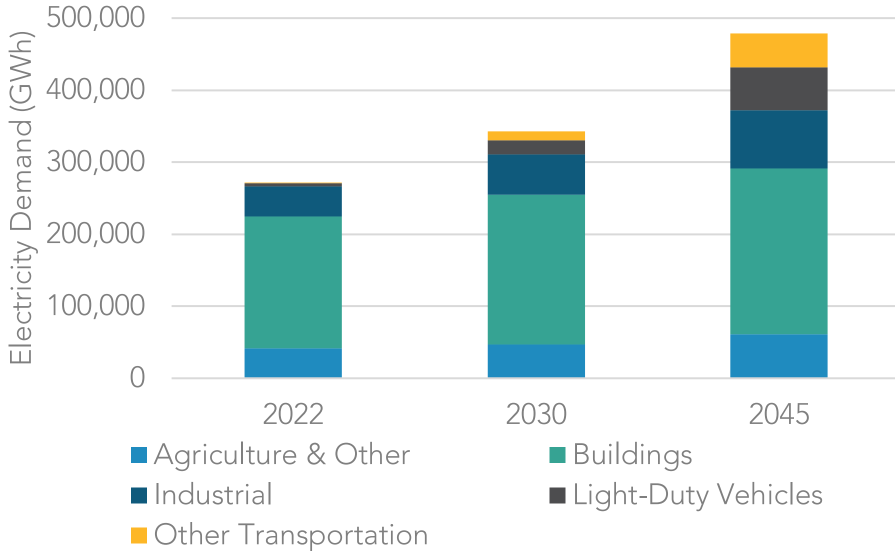
[368] SB 846 requires that load-serving entities exclude energy, capacity, or any attribute from the Diablo Canyon power plant in their resource plans. The Scoping Plan Scenario excludes energy, capacity, or any attribute from the Diablo Canyon power plant after the prior planned retirement date of 2025.
[369] The amount of additional customer solar included in the Scoping Plan Scenario is 29,208 MW by 2045.
[370] E3. 2022. CARB Scoping Plan: AB32 Source Emissions Final Modeling Results. PowerPoint. *https://ww2.arb.ca.gov/sites/default/files/2022-11/SP22-MODELING-RESULTS-E3-PPT.pdf*. Build rates are from EIA data historical builds in the 2011–2021 time frame.
[371] The estimate does not include hydrogen production assumed to be produced with bioenergy with carbon capture and storage (BECCS) and steam methane reforming (SMR).

**Figure 4-5: Projected new electricity resources needed by 2045 in the Scoping Plan Scenario**[372]




[372] See *https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx* for the capacity build-out by resource type.

**Figure 4-6: Electric loads in 2022, 2030 and 2045 for the Scoping Plan Scenario[373]**




This transformation will drive investments in a large fleet of generation and storage resources but will also require significant transmission to accommodate these new capacity additions. Transmission needs include high-voltage lines to access out-of-state resources and major in-state generation pockets. In consideration of typical 8- to 10-year lead times for many projects, the CAISO published its first 20-Year Transmission Outlook to inform transmission planning focused on meeting the needs identified through the 2021 SB 100 Joint Agency Report process. The outlook calls for significant transmission development to access offshore wind and out-of-state wind and reinforce the existing CAISO footprint at an estimated cost of $30.5 billion.[374]

Presently, fossil gas power plants provide about 75 percent of the flexible capacity for grid reliability as more renewable power enters the system. Moving forward, other resources such as storage and demand-side management are essential to maintain reliability with high concentrations of renewables. Hydrogen produced from renewable resources and renewable feedstocks can serve a dual role as a low-carbon fuel for existing combustion turbines or fuel cells, and as energy storage for later use. Reliability

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[373] *Other Transportation* includes all non-light-duty vehicles and reflects electrification of modes like passenger and freight rail, aviation, and ocean-going vessels.
[374] CAISO. 2022. *20 Year Transmission Outlook*. http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

also can be supported through increased coordination and markets in the interconnected western power grid; this is already helping to better integrate renewables.[375]

**Strategies for Achieving Success**

- Use long-term planning processes (Integrated Energy Policy Report, IRP, CAISO Transmission Planning Process, AB 32 Climate Change Scoping Plan) to support grid reliability and expansion of renewable and zero-carbon resource and infrastructure deployment.
- Complete systemwide and local reliability assessments across CAISO and other balancing authority areas, using realistic assumptions for land use, build rates, statewide and distribution system level constraints, and energy needs. Such assessments should be completed before state agencies update their electricity sector GHG targets.
- Prioritize actions to mitigate impacts to electricity reliability and affordability and provide sufficient flexibility in the state's decarbonization roadmap for adjustments as may be needed.
- Facilitate long lead-time resource development through the IRP and the SB 100 interagency process and through technology development and demonstration funding[376] that includes resources such as long-duration energy storage and hydrogen production.
- Continue coordination between energy agencies and energy proceedings to maximize opportunities for demand response.
- Continue to explore the benefits of regional markets to enhance decarbonization, reliability, and affordability.
- Address resource build-out challenges, including permitting, interconnection, and transmission network upgrades.
- Explore new financing mechanisms and rate designs to address affordability.[377]
- Per SB 350, double statewide energy efficiency savings in electricity and fossil gas end uses by 2030, through a combination of energy efficiency and fuel substitution actions.[378]
- Per SB 100 and SB 1020, achieve 90 percent, 95 percent, and 100 percent

[375] CEC. 2021. *2021 SB 100 Joint Agency Report – Achieving 100 Percent Clean Electricity in California: An Initial Assessment.* Publication Number: CEC-200-2021-001.

[376] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, ES2. The committee recommendation speaks specifically to offshore wind production. *finalejacrecs.pdf (arb.ca.gov)*.

[377] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF30. *finalejacrecs.pdf (arb.ca.gov)*.

[378] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

renewable and zero-carbon retail sales by 2035, 2040, and 2045, respectively.

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Target programs and incentives to support and improve access to renewable and zero-carbon energy projects (e.g., rooftop solar, community owned or controlled solar or wind, battery storage, and microgrids) for communities most at need, including frontline, low-income, rural, and indigenous communities.[379]
- Prioritize public investments in zero-carbon energy projects to first benefit the most overly burdened communities affected by pollution, climate impacts, and poverty.[380]

## Sustainable Manufacturing and Buildings

Fossil gas is the primary gaseous fossil fuel used to produce heat at industrial facilities, as well as in residential and commercial buildings. In buildings, space and water heating, cooking, and clothes drying all rely on gaseous fuels today. Industrial processes that require heat for conventional boilers and other processes also rely on gaseous fuels. Refineries rely on fossil gas and other gaseous fossil fuels, like liquefied petroleum gas and refinery fuel gas, and fossil gas is also used to generate electricity, as discussed earlier.

Gaseous fossil fuel use can be displaced by four primary alternatives: zero-carbon electricity, solar thermal heat, hydrogen, and biogas/biomethane. Displacing gaseous fossil fuel use can yield indoor air quality benefits, protect public health and property from unexpected fossil gas leaks, and reduce short-lived climate pollutants, which are many times more potent in affecting climate change than $CO_2$. The Scoping Plan Scenario reduces dependence on fossil gas in the industrial and building sectors by transitioning substantial energy demand to alternative fuels. Reducing fossil gas combustion also will help toward achieving our air quality and equity goals by reducing pollution in neighboring areas and communities. In addition, reduced dependence on gasoline and diesel in the transportation sector diminishes the need for gaseous fossil fuels to support oil and gas production and petroleum refining operations as those are phased down relative to the demand.

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[379] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2, NF9, NF11, NF12, NF13. finalejacrecs.pdf (arb.ca.gov).

[380] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF14. finalejacrecs.pdf (arb.ca.gov).

## Sector Transition

### Industry

California's industrial sector contributes significantly to the state's economy, with a total output from manufacturing in 2019 of $324 billion (10.4 percent of the state total)[381] and employment of 1,222,000 manufacturing jobs (7.6 percent of the total state workforce).[382] California industry includes a diverse range of facilities, including cement plants, refineries, glass manufacturers, oil and gas producers, paper manufacturers, mining operations, metal processors, and food processors. Combustion of fossil gas, other gaseous fossil fuels, and solid fossil fuels provide energy to meet three broad industry needs: electricity, steam, and process heat. Non-combustion emissions result from fugitive emissions and from the chemical transformations inherent to some manufacturing processes. About 20 percent of the GHG emissions from the industrial sector are non-combustion emissions.

Decarbonizing industrial facilities depends upon displacing fossil fuel use with a mix of electrification, solar thermal heat, biomethane, low- or zero-carbon hydrogen, and other low-carbon fuels to provide energy for heat and reduce combustion emissions. Emissions also can be reduced by implementing energy efficiency measures and using substitute raw materials that can reduce energy demand and some process emissions. Some remaining combustion emissions and some non-combustion $CO_2$ emissions can be captured and sequestered. The strategy employed will depend on the industrial subsector and the specific processes utilized in production. The left side of Figure 4-7 illustrates the fuels used to meet industrial manufacturing energy demand in 2020. Industrial manufacturing energy demand needs to transition to the fuel mix shown for 2035 and 2045. The right side of Figure 4-7 illustrates the fuel mix needed to meet the energy demand of oil and gas extraction and petroleum refining operations for the same years. Energy demand in this portion of the industrial sector declines along with decreased demand for gasoline and diesel in the transportation sector. In both figures there is a continuing demand for fossil gas due to lack of non-combustion technologically feasible or cost-effective alternatives for certain industrial sectors. Policies that support decarbonization strategies like electrification, use of renewable energy, and transition to alternative fuels are needed.

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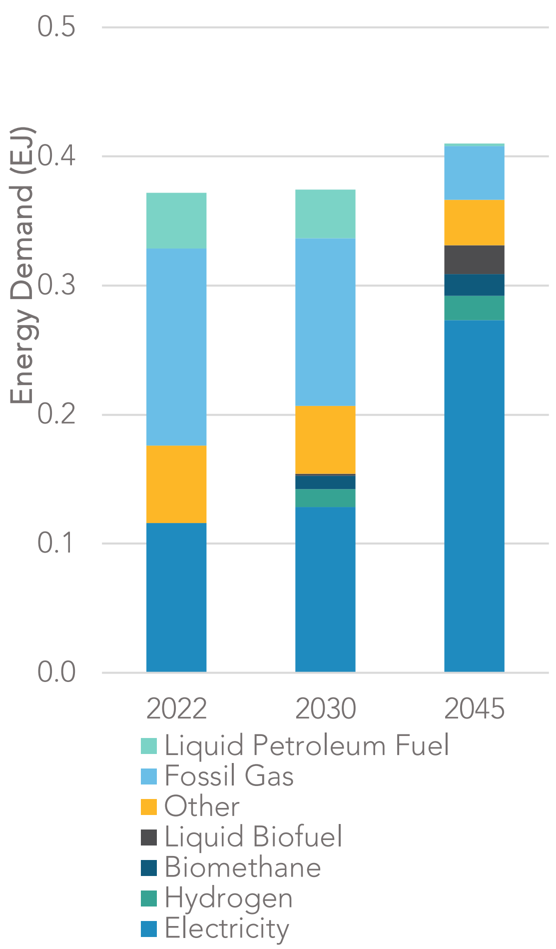
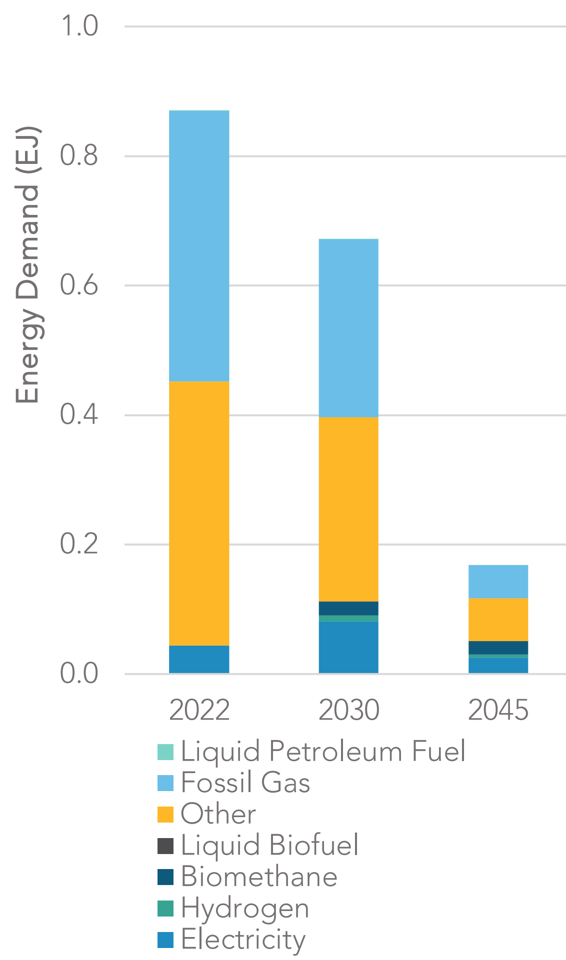
[381] National Association of Manufacturers (NAM). 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.

[382] NAM. 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.

**Figure 4-7: Final energy demand in industrial manufacturing (left) and in oil and gas extraction and petroleum refining (right) in 2022, 2030, and 2045 in the Scoping Plan Scenario[383]**




Electrification and solar thermal heat are best-suited to industrial processes that have relatively low heat requirements, such as food processors, paper mills, and industries that use low-pressure steam in their processes. Approaches could include replacing fossil gas boilers with electric boilers, process heaters with industrial electric heat pumps, steel forging furnaces with induction heaters, and implementing other sector-specific process electrification. Under current rate structures for industrial electricity and fossil gas in

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[383] *Other* fuel in the industrial manufacturing sector is primarily coke and coal for cement production. *Other* fuel in the petroleum refining sector is primarily fossil gas associated with refining petroleum products.

California, most projects to electrify a fossil gas-powered industrial process will face operating cost barriers and potential reliability concerns. Microgrids powered by renewable resources and with battery storage are emerging as a key enabler of electrification and decarbonization at industrial facilities.

There are fewer commercially available and economically viable electrification options to replace industrial processes that require higher-temperature heat. For these processes, onsite combustion may continue to be needed, and decarbonization will require fuel substitution to hydrogen,[384] biomethane, or other low-carbon fuels. Fuel substitution and continued combustion will require monitoring and mitigation of any potential air quality impacts, especially in low-income and communities of color which already face disproportionate air pollution burdens. Industries in California with high heat needs include steel forging, glass manufacturing, and industries with calcination processes, such as manufacturing lime and cement.

Onsite emissions from cement manufacturing derive from two main sources: (1) fuel combustion to heat the kiln to a very high temperature and (2) process $CO_2$ emissions from the chemical transformation of limestone. Over 60 percent of emissions from the sector are process emissions unrelated to fuel use, and most emissions related to fuel use are from coal and petroleum coke combustion. Process emissions from cement manufacturing are significant and will continue even if the sector were to operate using only zero-carbon fuels; thus carbon capture and use/sequestration will be a likely component of any strategy to fully decarbonize cement manufacturing. There are additional opportunities to reduce GHG emissions from cement manufacturing via the combination of fuel-switching to low-carbon fuels (e.g., biomethane, municipal solid waste, biochar), increased blending of non-clinker materials, and efficiency improvements. High technological and economic barriers exist to electrifying kiln process heat at cement plants, as clinker production requires temperatures in excess of 1,500°C. There are potential decarbonization opportunities throughout the value chain of cement use, including in cement manufacturing, concrete mixing, and construction practices.[385] SB 596 (Becker, Chapter 246, Statutes of 2021), which was signed by Governor Newsom in September 2021, requires CARB to develop a comprehensive strategy for cement use in California to achieve a GHG intensity 40 percent below 2019 levels by 2035, and net-zero emissions by 2045.

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[384] Griffiths, Steve, Benjamin K. Sovacool, Jinsoo Kim, Morgan Bazilian, and Joao M. Uratani. 2021. "Industrial decarbonization via hydrogen: A critical and systematic review of developments, socio-technical systems and policy options." *Energy Research & Social Science* 80. 102208, ISSN 2214-6296. https://doi.org/10.1016/j.erss.2021.102208.
[385] California Nevada Cement Association. Achieving Carbon Neutrality in the California Cement Industry. https://cncement.org/attaining-carbon-neutrality.

Oil and gas extraction and refining make up over half of California's industrial GHG emissions. Reduced demand for transportation fossil fuels corresponds to reduced supply of fossil gas and other gaseous fossil fuels for refineries to produce these fuels. Some refining operations will continue to operate to produce fossil fuel for the remaining transportation energy demands, along with renewable diesel and sustainable aviation fuel, as discussed in the Transportation Sustainability section of this chapter.

Across industrial subsectors and processes, California facilities also could realize significant reductions in GHG emissions and energy-related costs by implementing advanced energy efficiency projects and tools.[386] While enhanced operation and maintenance practices are typical at industrial facilities, additional strategic energy management practices offer greater efficiency gains by focusing on setting goals, tracking progress, and reporting results.

**Strategies for Achieving Success**

- Maximize air quality benefits using the best available control technologies for stationary sources in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[387]
- Prioritize alternative fuel transitions first in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[388]
- Invest in research and development and pilot projects to identify options to reduce materials and process emissions along with energy emissions in California's industrial manufacturing facilities, leveraging programs like the CEC's Electric Program Investment Charge (EPIC).[389]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Support electrification with changes to industrial rate structures.
- Develop infrastructure for CCS and hydrogen production to reduce GHG emissions where cost-effective and technologically feasible non-combustion alternatives are not available.
- Implement SB 905.

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[386] Therkelsen, Peter, Aimee McKane, Ridah Sabouini, and Tracy Evans. 2013. *Assessing the Costs and Benefits of the Superior Energy Performance Program.* U.S Department of Energy. https://www.osti.gov/servlets/purl/1165470.
[387] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT14. *finalejacrecs.pdf (arb.ca.gov)*.
[388] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT15. *finalejacrecs.pdf (arb.ca.gov)*.
[389] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, M20. *finalejacrecs.pdf (arb.ca.gov)*.

- Establish markets for low-carbon products and recycled materials using Buy Clean California Act and other mechanisms relying on robust data
- Develop a net-zero cement strategy to meet SB 596 targets for the GHG intensity of cement use in California.
- Continue to leverage energy-efficiency programs, including the U.S. DOE's ENERGY STAR program,[390] U.S. DOE's Superior Energy Performance program,[391] and ISO 50001.[392]
- Evaluate and continue to offer incentives to install energy efficiency and renewable energy technologies through programs such as CPUC decisions as part of rulemaking R.19-09-009[393] and the CEC's Food Production Investment Program (FPIP) and EPIC programs.[394]
- Leverage low-carbon hydrogen programs, including the Bipartisan Infrastructure Law, for regional hydrogen hubs, hydrogen electrolysis, and hydrogen manufacturing and recycling.
- Evaluate the role of hydrogen in meeting GHG emission reductions, including policy recommendations regarding the use of hydrogen in California as required by SB 1075.
- Address cost barriers to promote low-carbon fuels for hard-to-electrify industrial applications.

## Buildings

Buildings have cross-sector interactions that influence our public health and well-being and affect land use and transportation patterns, energy use, water use, and indoor and outdoor environments.[395] There are about 14 million existing homes and over 7.5 billion square feet of existing commercial buildings[396] in California. Fossil gas supplies about half of the energy consumed by end uses in these buildings. In addition to GHG emissions, fossil gas usage in buildings also produces $CO_2$, NOx, $PM_{2.5}$, and

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[390] ENERGY STAR. ENERGY STAR Guidelines for Energy Management. https://www.energystar.gov/buildings/tools-and-resources/energy-star-guidelines-energy-management.

[391] Energy.gov. Superior Energy Performance 50001. https://www.energy.gov/eere/amo/superior-energy-performance.

[392] ISO. ISO 50001 Energy Management. https://www.iso.org/iso-50001-energy-management.html.

[393] CPUC. January 14, 2021. CPUC Adopts Strategies to Help Facilitate Commercialization of Microgrids Statewide. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M360/K370/360370887.PDF.

[394] Bailey, Stephanie, David Erne, and Michael Gravely. 2021. *Final 2020 Integrated Energy Policy Report Update, Volume II: The Role of Microgrids in California's Clean and Resilient Energy Future, Lessons Learned From the California Energy Commission's Research.* California Energy Commission. Publication Number: CEC-100-2020-001-V2-CMF.

[395] See Appendix F (Building Decarbonization).

[396] CEC. 2021. California Building Decarbonization Assessment. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311&DocumentContentId=72767.

formaldehyde.[397] Each year, about 120,000 new homes[398] and more than 100 million-square feet[399] of commercial buildings are newly constructed across California. These new buildings will represent between a third to half of the total building stock by mid-century.

Achieving carbon neutrality must include transitioning away from fossil gas in residential and commercial buildings, and will rely primarily on advancing energy efficiency while replacing gas appliances with non-combustion alternatives. This transition must include the goal of trimming back the existing gas infrastructure so pockets of gas-fueled residential and commercial buildings do not require ongoing maintenance of the entire limb for gas delivery. Blending low-carbon fuels such as hydrogen and biomethane into the pipeline further displaces fossil gas. Pipeline safety and reliability must be evaluated to accommodate low-carbon fuels. Figure 4-8 illustrates the energy Californians use in buildings at present compared with the Scoping Plan Scenario, which introduces alternatives to fossil gas. In that scenario almost 90 percent of energy demand is electrified by 2045, and the remaining energy demand is met with combustion of hydrogen, biomethane, and fossil gas.

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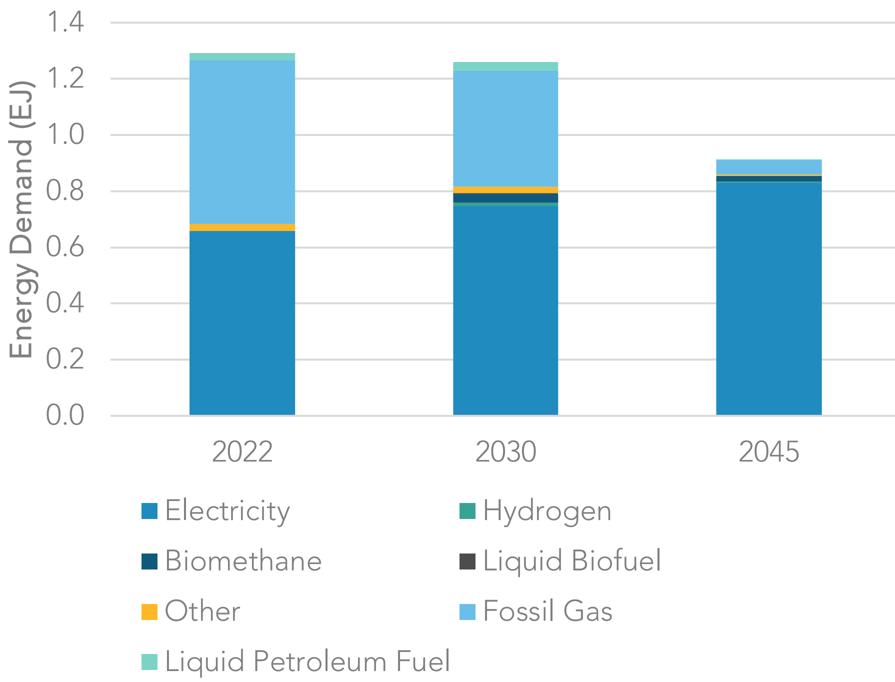
[397] Zhu, Yifang, et al. 2020. *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California.* UCLA Fielding School of Public Health Department of Environmental Health Sciences.
[398] Construction Industry Research Board. 2018. Annual Building Permit Summary. [http://www.cirbreport.org](http://www.cirbreport.org).
[399] Delforge, Pierre. August 11, 2021. California Forging Ahead on Zero Emission Buildings. Blog. NRDC. [https://www.nrdc.org/experts/pierre-delforge/california-forging-ahead-zero-emission-buildings](https://www.nrdc.org/experts/pierre-delforge/california-forging-ahead-zero-emission-buildings).

**Figure 4-8: Final energy demand in buildings in 2022, 2030, and 2045 in the Scoping Plan Scenario**[400]

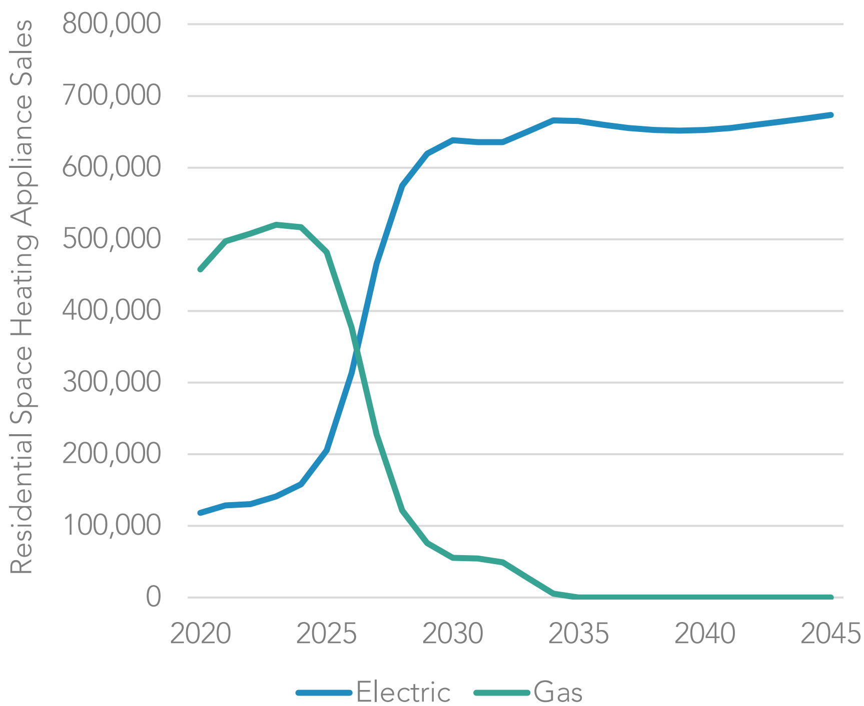



This transition is achieved when all new buildings constructed include non-combustion appliances, and appliances in existing buildings are replaced at the end of their useful life with non-combustion alternatives. Currently, electric alternatives, combined with the decarbonizing of California's grid, are the most effective alternatives, and the Scoping Plan Scenario modeled these alternatives. The Scoping Plan Scenario assumes three million all-electric and electric-ready homes by 2030 and seven million by 2035. Figure 4-9 illustrates the pace at which electric space heating appliance sales increase and gas space heating appliance sales decrease in residences in the Scoping Plan Scenario, such that by 2035 100 percent of residential home appliance sales are electric. By 2030 over six million electric heat pumps are installed statewide. The residential electric space heating appliance sales increases rapidly in the near term as new all-electric buildings are constructed and as existing buildings are renovated to utilize electric appliances. A similar transition is envisioned for other home appliances. Commercial buildings also will undergo a transition away from gas appliances to electric appliances, achieving 80 percent sales of all-electric appliances by 2035 and 100 percent by 2045. Appendix F (Building Decarbonization) describes a holistic policy approach to rapidly grow the

[400] *Other* fuel in the buildings sector is primarily liquid petroleum gas and waste heat.

number of zero emission appliances and buildings, to surmount the market barriers, and to prioritize an equitable transition for vulnerable communities.

**Figure 4-9: Residential space heating appliance sales in the Scoping Plan Scenario**




**Strategies for Achieving Success**

- Prioritize California's most vulnerable residents with the majority of funds in the new $922 million Equitable Building Decarbonization program, created through the 2022–2023 state budget. This would include residents in frontline, low-income, disadvantaged, rural, and tribal communities. This program is dedicated to a statewide direct-install building retrofit program for low-income households to replace fossil fuel appliances with electric appliances, energy-efficient lighting, and building insulation and sealing while also coordinating reductions in gas infrastructure in specific geographic areas.
- Achieve three million all-electric and electric-ready homes by 2030 and seven million by 2035 with six million heat pumps installed statewide by 2030.
- Expand incentive programs to support the holistic retrofit of existing buildings, especially for vulnerable communities.
- Ensure that incentive programs prioritize energy affordability and tenant protections, promote affordable and low-income household retrofits that improve habitability and reduce expenses, protect and empower small landlords and homeowners, address overlooked consumer groups, and pair decarbonization

with other critically needed renovation efforts to ensure that buildings support human health and are climate- and weather-resistant.[401]

- End fossil gas infrastructure expansion for newly constructed buildings.[402]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Strengthen California's building standards to support zero-emission new construction.
- Develop building performance standards for existing buildings.
- Adopt a zero-emission standard for new space and water heaters sold in California beginning in 2030, as specified in the 2022 State Strategy for the State Implementation Plan.
- Expand use of low-GWP refrigerants within buildings.
- Support electrification with changes to utility rate structures and by promoting load management programs.
- Increase funding for incentive programs and expand financing assistance programs focused on existing buildings and appliance replacements.
- Expand consumer education efforts to raise awareness and stimulate the adoption of decarbonized buildings and appliances, especially in vulnerable communities.
- Implement biomethane procurement targets for investor-owned utilities as specified in SB 1440 (Hueso, Chapter 739, Statutes of 2018) to reduce GHG emissions in remaining pipeline gas and reduce methane emissions from organic waste.

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[401] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF23, NF24, NF25, NF26, NF28. *finalejacrecs.pdf (arb.ca.gov)*.

[402] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. *finalejacrecs.pdf (arb.ca.gov)*.

## Carbon Dioxide Removal and Capture

*Climate Change 2022: Mitigation of Climate Change,*[403] a report by the IPCC released in early 2022, states "The deployment of CDR to counterbalance hard-to-abate residual emissions is unavoidable if net zero $CO_2$ or GHG emissions are to be achieved. The scale and timing of deployment will depend on the trajectories of gross emission reductions in different sectors. Upscaling the deployment of CDR depends on developing effective approaches to address feasibility and sustainability constraints especially at large scales." In line with that report, this Scoping Plan considers CDR as a complement to technologically feasible and cost-effective GHG emissions mitigation, and the size of its role will depend on the degree of success in reducing GHG emissions at the source across the economy. [404] The modeling shows that emissions from the AB 32 GHG Inventory sources will continue to persist even if all fossil related combustion emissions are phased out. These residual emissions must be compensated for to achieve carbon neutrality. Options for CDR include both sequestration in natural and working lands and mechanical approaches like direct air capture. Chapter 2 provides estimates on how much $CO_2$ removal is possible by our natural and working lands and how much must be removed by mechanical CDR.

CCS, which is carbon capture from anthropogenic point sources, is described in Chapter 2 and involves capturing carbon from a smokestack of an emitting facility. Direct air capture, on the other hand, captures carbon directly from the atmosphere. Direct air capture technologies, unlike CCS, are not associated with any particular point source.

For this section, *carbon management* refers to the capture, movement, and sequestration of $CO_2$ through mechanical solutions for both capture at point sources and direct removal from the atmosphere through direct air capture.[405] Enabling policies and regulations across each of these steps are necessary for individual projects, and on a broader scale, for delivering reductions in support of the state's carbon neutrality and long-term carbon-negative goals. Figure 4-10 provides a graphic of the typical carbon management infrastructure.

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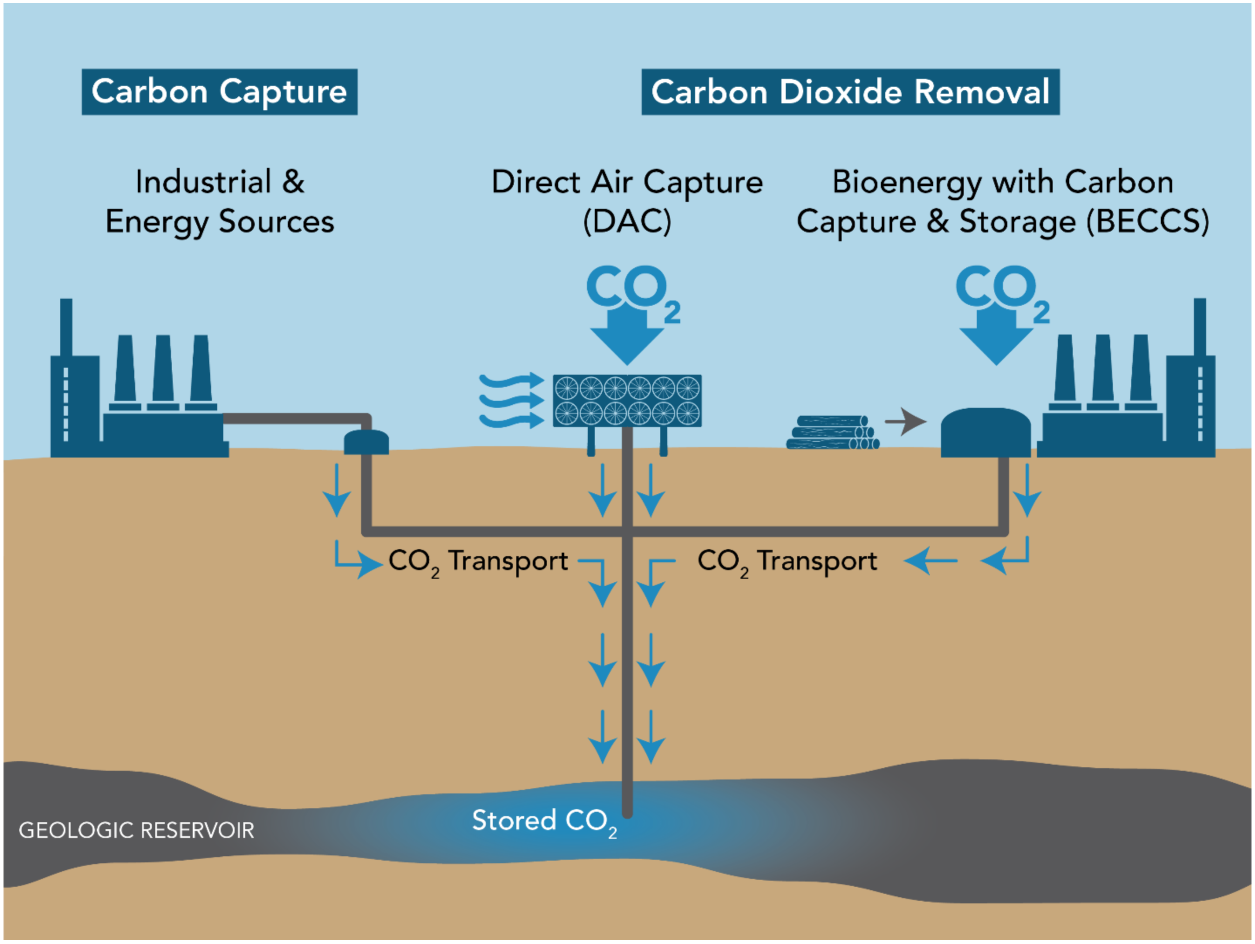
[403] IPCC. 2022. *Climate Change 2022: Mitigation of Climate Change.* https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/.

[404] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.7. finalejacrecs.pdf (arb.ca.gov).

[405] CDR through natural and working lands is discussed in Chapter 2 and later in this chapter.

**Figure 4-10: Carbon management infrastructure**




Carbon dioxide removal directly from the atmosphere itself refers to a suite of carbon negative technologies that can be used to draw down ongoing and historical carbon emissions already in the atmosphere. Some $CO_2$ removal technologies leverage the abilities of both natural photosynthesis and mechanical removal by using biomass wastes as inputs to make low- or zero-carbon energy or fuels, all while capturing and storing produced $CO_2$.

Captured $CO_2$ from point sources or from the atmosphere is permanently stored in specialized geologic formations, typically half a mile or more underground. A recent Stanford University study estimated the state's commercial storage potential is nearly 70,000 million metric tons of $CO_2$, even when excluding oil and gas reservoirs.[406] California is well-positioned because few other places on the West Coast are suitable for

[406] Stanford Center for Carbon Storage. Opportunities and Challenges for CCS in California. https://sccs.stanford.edu/california-projects/opportunities-and-challenges-for-CCS-in-California.

geologic storage at scale. To inform discussion around $CO_2$ removal, CARB held two full-day workshops exploring the types of options for carbon capture and geologic storage and utilization in products.[407,408,409]

The modeling results provided in Chapter 2 demonstrate the targeted need for CCS on large facilities such as refineries and cement. The CCS numbers do not include the potential additional applications for producing hydrogen with biomethane, other manufacturing, electricity, or other bioenergy. If CCS is not deployed, those emissions would be released directly into the atmosphere and instead need to be addressed through CDR to achieve carbon neutrality. Although a study finds California has 76 existing electricity and industrial facilities that are suitable candidates for CCS retrofit,[410] this Scoping Plan proposes a targeted role for this technology such that it would only be used to address sectors where non-combustion options are not technologically feasible or cost-effective at this time, to the extent needed to achieve the 85 percent reduction in anthropogenic emissions as called for in AB 1279. In future updates to the Scoping Plan, there may be additional options for technologically feasible or cost-effective technologies that may be deployed, which would further reduce the need for CCS and CDR except in situations to address historical GHG emissions.

Recognizing the need for carbon capture and utilization sequestration and removal, the Legislature passed, and the governor signed, SB 905. It includes several key requirements in the development of the state's Carbon Capture Removal, Utilization, and Storage Program. The following is a summary of the work to be completed to establish and administer this program. Many of these steps will address the need to evaluate the safety and efficacy of actions to support carbon removal, sequestration, and transfer via pipelines. Note that not all of these actions are under CARB's authority.

- Review technology to evaluate efficacy, safety, viability of CCUS/CDR methodologies.
- Develop monitoring and reporting requirements and schedules.
- Develop a unified permit application.
- Develop financial responsibility requirements.
- Develop a centralized public database for project status.

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[407] CARB. December 11, 2019. Carbon Neutrality Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/carbon-neutrality/carbon-neutrality-meetings-workshops*.
[408] CARB. August 2, 2021 Scoping Plan Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops*.
[409] *Carbon utilization* refers to the use of captured carbon to produce products such as plastics and concrete.
[410] Glenwright, Kara. 2020. *Roadmap for carbon capture and storage in California.* Precourt Institute for Energy. *https://earth.stanford.edu/news/roadmap-carbon-capture-and-storage-california#gs.ysj78q.*

- Consult with CNRA on pore space requirements as CNRA develops a framework for pore space governing agreements.
- Establish a Geologic Carbon Sequestration Group to identify suitable injection well locations, subsurface monitoring, and potential hazards that may require suspension of injection.

SB 905 also has requirements for project developers such as to develop monitoring plans and to avoid any adverse health and environmental impacts at the carbon capture location—or mitigation of unavoidable impacts as required under existing requirements. For the site of injection, there are requirements for site stability, monitoring, and reporting plans. SB 905 also bans CCS with enhanced oil recovery in California and prohibits the transfer of $CO_2$ via pipeline until the U.S. Department of Transportation's Pipelines and Hazardous Materials Safety Administration (PHMSA) completes its current rulemaking to update existing $CO_2$ pipeline safety requirements.

An often-cited example of pipeline concerns involves a $CO_2$ pipeline in Mississippi. On February 22, 2020, a $CO_2$ pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld (DOT 2022). The combination of weather and topography resulted in a slower dissipation of the gas. The pipeline was also carrying hydrogen sulfide, a flammable and toxic gas. The pipeline failed on a steep embankment, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. The PHMSA investigation also revealed several contributing factors to the accident, including but not limited to: Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its $CO_2$ dispersion model, and not notifying local responders to advise them of a potential failure.

As the Satartia example highlights, appropriate pipeline safety and environmental standards in California are critical to minimize any risks from $CO_2$ transport in the future. As such, SB 905 also tasks CNRA, in consultation with the Public Utilities Commission, to, no later than February 1, 2023, provide a proposal to the Legislature to establish a state framework and standards for the design, operation, siting, and maintenance of intrastate pipelines carrying $CO_2$ fluids of varying composition and phase to minimize the risk posed to public and environmental health and safety. The recommended framework shall be designed to minimize risk to public health and environmental health and safety, to the extent feasible. Because SB 905 prohibits the transfer of $CO_2$ via pipeline until the PHMSA completes its current rulemaking to update existing $CO_2$ pipeline safety requirements, CCS or CDR projects that would require a pipeline to transfer $CO_2$ are not feasible at this time within California.

Ultimately, and in accordance with SB 905, the merits of each CCS or CDR project must be evaluated on a case-by-case basis.[411] Deployment of CCS and CDR could support skilled jobs and workforces, including those in traditional fossil energy communities. Other co-benefits could include criteria air pollutant reductions and water production. It will be important to design projects that do not exacerbate community health impacts, include early and ongoing community engagement, and are in compliance with local, state, and federal public health and environmental protection laws. It also should be noted that, as these types of projects are an emerging area of governance, additional coordination and discussion will be needed among the various levels of authorities involved. SB 905 has already initiated this process by assigning specific agencies with tasks related to their expertise and authority.

Chapter 2 includes a more detailed discussion about the proposed role of $CO_2$ removal in this Scoping Plan.

## Sector Transition

State,[412] national,[413,414] and global decarbonization analyses[415] indicate a significant role for carbon management infrastructure, yet relatively few projects are operational. Around the world, about two dozen large CCS projects are capturing tens of millions of metric tons of $CO_2$ each year, with about a dozen operating in the United States.[416] The vast majority of capacity is at industrial facilities, such as ethanol and fertilizer plants, that would otherwise vent nearly pure $CO_2$ into the atmosphere as a by-product of normal, non-combustion processes. Future research, development, and demonstration projects must refine and commercialize capture systems for more complex applications, especially

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[411] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.5. finalejacrecs.pdf (arb.ca.gov).

[412] E3. October 2020. Achieving Carbon Neutrality in California Report: Final Presentation. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_presentation_oct2020_2.pdf.

[413] World Resources Institute. January 31, 2020. CarbonShot: Federal Policy Options for Carbon Removal in the United States. Working paper. https://www.wri.org/research/carbonshot-federal-policy-options-carbon-removal-united-states.

[414] C2ES. No date. Getting to Zero: A U.S. Climate Agenda — Center for Climate and Energy Solutions. https://www.c2es.org/getting-to-zero-a-u-s-climate-agenda-report/.

[415] IPCC. Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. Chapter 2. https://www.ipcc.ch/sr15/chapter/chapter-2/. All analyzed pathways limiting warming to 1.5°C with no or limited overshoot use CDR to some extent to neutralize emissions from sources for which no mitigation measures have been identified and, in most cases, also to achieve net negative emissions to return global warming to 1.5°C following a peak (high confidence). The longer the delay in reducing $CO_2$ emissions toward zero, the larger the likelihood of exceeding 1.5°C, and the heavier the implied reliance on net negative emissions after mid-century to return warming to 1.5°C (high confidence).

[416] Congressional Research Service. 2021. Carbon Capture and Sequestration (CCS) in the United States. R44902. https://crsreports.congress.gov/product/pdf/R/R44902?msclkid=e45e0012c25911ec8085ca575cb61e82.

for those with limited decarbonization options. It has only been in the last few years that attention has seriously turned to mechanical CDR. As new information and modeling on climate change have been made available, the science has become clearer that avoiding the most catastrophic impacts of climate change requires both reducing emissions and deploying mechanical CDR.

California is paving a path forward on a science-based carbon management infrastructure policy that can serve as an example for other jurisdictions. The LCFS, which reduces the carbon intensity of transportation fuels, includes a protocol for select carbon management projects to become certified and generate LCFS credits.[417] CCS is not a new concept or technology. Twenty years of CCS testing show it is a safe and reliable tool.[418] As mentioned in Chapter 2, while no new CCS projects have been implemented or generated any credits under the CARB CCS protocol, CCS projects have been implemented elsewhere since the 1970s. Moreover, there has been a U.S. Department of Energy CCS research program underway for more than two decades. These all form a foundation of information for future efforts. Certified projects must successfully demonstrate adherence to rigorous pre-construction, operational, and site closure standards designed to strengthen environmental performance, as described in CARB's CCS Protocol. The protocol is designed to layer on top of existing federal carbon sequestration regulations designed to protect the environment. The protocol would need to be reevaluated if CCS were to be more broadly applied across sectors beyond transportation fuel production.

Direct air capture and carbon mineralization have high potential capacity for removing carbon, but direct air capture is currently limited by high cost. Carbon mineralization may also have high potential for removing carbon from the atmosphere, but understanding of the technology is still limited.[419] Direct air capture could also be deployed at higher rates to remove legacy GHG emissions from the atmosphere. Chapter 2 contains additional information on the current status of CCS and mechanical CDR projects globally, as well as federal support of such technologies.

**Strategies for Achieving Success**

- Implement SB 905.

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[417] CARB. 2018. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard. August 13. https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf.

[418] National Energy Technology Laboratory. Permanence and Safety of CCS. https://netl.doe.gov/coal/carbon-storage/faqs/permanence-safety.

[419] Aines, Roger. No date. Options for Removing $CO_2$ from California's Air. Lawrence Livermore National Laboratory. https://ww2.arb.ca.gov/sites/default/files/2021-08/llnl_presentation_sp_engineeredcarbonremoval_august2021.pdf.

- Convene a multi-agency Carbon Capture and Sequestration Group comprised of federal, state, and local agencies to engage with environmental justice advocates, tribes, academics, researchers, and community representatives to identify the current status, concerns, and outstanding questions concerning CCS, and develop a process to engage with communities to understand specific concerns and consider guardrails to ensure safe and effective deployment of CCS.[420]
- Iteratively update the CARB CCS Protocol with the best available science and implementation experience.
- Incorporate CCS into other sectors and programs beyond transportation where cost-effective and technologically feasible options are not currently available and to achieve the 85 percent reduction in anthropogenic sources below 1990 levels as called for in AB 1279.
- Evaluate and propose, as appropriate, financing mechanisms and incentives to address market barriers for CCS and CDR.
- Evaluate and propose, as appropriate, the role for CCS in cement decarbonization (SB 596) and as part of hydrogen production pathways (SB 1075).
- Support carbon management infrastructure projects through core CEC research, development, and demonstration (RD&D) programs.
- Continue to explore carbon capture applications for producing or leveraging zero-carbon power for reliability needs as part of SB 100.
- Consider carbon capture infrastructure when developing hydrogen roadmaps and strategy, especially for non-electrolysis hydrogen production.
- Evaluate and streamline permitting barriers to project implementation while protecting public health and the environment.
- Explore options for how local air quality benefits can be achieved when CCS is deployed.
- Explore opportunities for CCS and CDR developers to leverage existing infrastructure, including subsurface infrastructure.
- Explore permitting options to allow for scaling the number of sources at carbon sequestration hubs.

## Short-Lived Climate Pollutants (Non-Combustion Gases)

Short-lived climate pollutants (SLCPs) include black carbon (soot), methane ($CH_4$), and fluorinated gases (F-gases, including hydrofluorocarbons [HFCs]). They are powerful climate forcers and harmful air pollutants that have an outsized impact on climate change

[420] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.9. finalejacrecs.pdf (arb.ca.gov).

in the near term, compared to longer-lived GHGs, such as $CO_2$. According to the IPCC's *Climate Change 2021: The Physical Science Basis,* in the near-term (i.e., 10- to 20-year time scale) the warming influence of all SLCPs combined will be at least as large as that of $CO_2$.[421] The United Nations Environment Programme's Global Methane Assessment[422] advises that achieving the least-cost pathways to limit warming to 1.5°C requires global methane emission reductions of 40–45 percent by 2030 alongside substantial simultaneous reductions of all climate forcers, including $CO_2$ and SLCPs. Action to reduce these powerful emissions sources today will provide immediate benefits—both to human health locally and to reduce warming globally—as the effects of our policies to transition to low carbon energy systems and achieve carbon neutrality further unfold.

In 2017, the Board approved the comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy).[423] This strategy explained how the state would meet the following SB 1383-established targets:

- 40 percent reduction in total methane emissions[424] (including a separate 40 percent reduction in dairy and livestock emissions)
- 40 percent reduction in hydrofluorocarbon gas emissions
- 50 percent reduction in anthropogenic black carbon emissions
- 50 percent reduction of organic waste disposal from 2014 levels by 2020, and 75 percent by 2025, including recovery of at least 20 percent of edible food for human consumption

The state is expected to achieve roughly half of the SB 1383 targeted emissions reductions by 2030 through strategies currently in place (See Figure 4-11). As directed by the Legislature under SB 1383, state agencies focused on voluntary, incentive-based mechanisms to reduce SLCP emissions in the early years of implementation to overcome technical and market barriers. Under this "carrot-then-stick" strategy, incentives are replaced with requirements as the solutions become increasingly feasible and cost-effective. To meet legislated targets, more aggressive action is needed.

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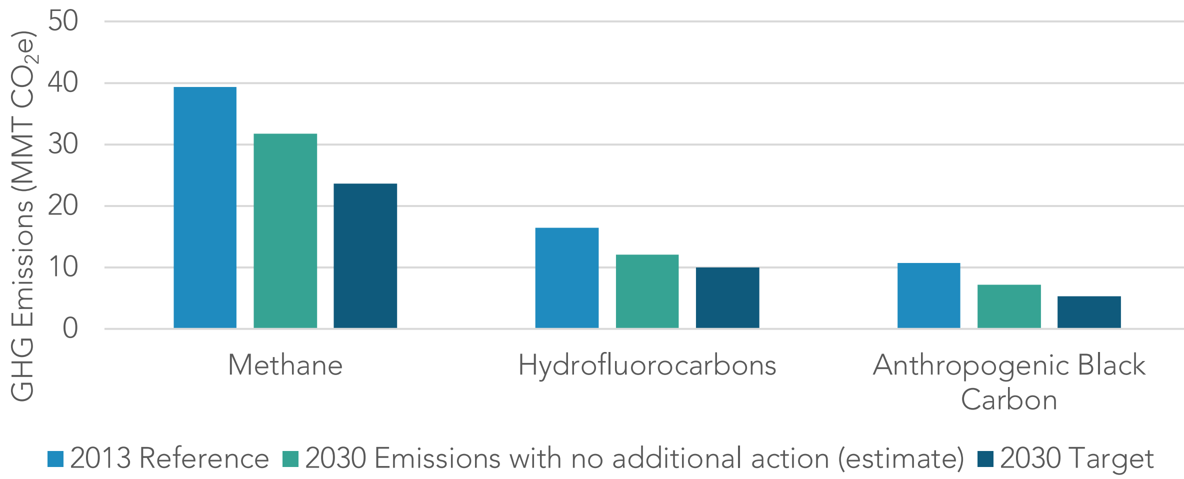
[421] IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.
[422] United Nations. Global Methane Assessment. Summary for Policymakers. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.
[423] CARB. 2017. Short-Lived Climate Pollution Reduction Strategy. https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
[424] All SB 1383 emissions reductions are mandated to be realized by 2030 and are relative to 2013 levels.

**Figure 4-11: Expected progress toward SB 1383 targeted emissions reductions by 2030 through strategies currently in place**




While the state's overall GHG emissions have declined by 9 percent over the past decade, SLCP emissions reductions have not kept pace with broader progress toward decarbonization. After growing steadily in the preceding decade, methane emissions have remained relatively flat since 2013.

HFCs are the fastest growing source of GHG emissions, primarily driven by their use to replace ozone-depleting substances and an increased demand for cooling and refrigeration.[425] Since 2005, statewide HFC emissions have more than doubled. While the rate of increase has slowed in recent years due to the state's measures, HFC emissions are still on the rise in California, and have grown by over 50 percent since 2010.[426] Globally, as temperatures rise, adoption of cooling technologies (and refrigerants) is increasing rapidly. If no measures are taken, it is estimated that HFCs will account for 9 to 19 percent of the total global GHG emissions by 2050.[427]

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[425] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[426] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[427] Velders, G. J., D. W. Fahey, J. S. Daniel, M. McFarland, and S. O. Andersen. 2009. "The large contribution of projected HFC emissions to future climate forcing." *Proceedings of the National Academy of Sciences* 106(27), 10949–10954.

## Methane

Human sources of methane emissions are estimated to be responsible for up to 25 percent of current warming.[428] Fortunately, methane's short atmospheric lifetime of ~12 years[429] means that emissions reductions will rapidly reduce concentrations in the atmosphere, slowing the pace of temperature rise in this decade. Further, a substantial portion of the targeted reductions can be achieved at low cost and will provide significant human health benefits. For example, the UN's *Global Methane Assessment* (2021)[430] found that over half of the available targeted measures have mitigation costs below \$21/MT$CO_2$e, and that each million metric tons of methane reduced would prevent 1,430 premature deaths annually due to ozone pollution caused by methane.

Following the Twenty Sixth Conference of Parties (COP26) (the United Nations Convention on Climate Change in 2021), over 110 nations have signed onto the Global Methane Pledge (Pledge)[431] to limit methane emissions by 30 percent relative to 2020 levels. The Pledge covers countries that emit nearly half of all methane and make up 70 percent of global GDP. The UN's Global Methane Assessment[432] shows that human-caused methane emissions can be reduced by up to 45 percent this decade, which would avoid nearly 0.3°C of global warming by 2045.

As shown in Figure 4-12, the three largest sources of California's methane emissions are the dairy and livestock industry, landfills, and oil and gas systems.

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428 IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

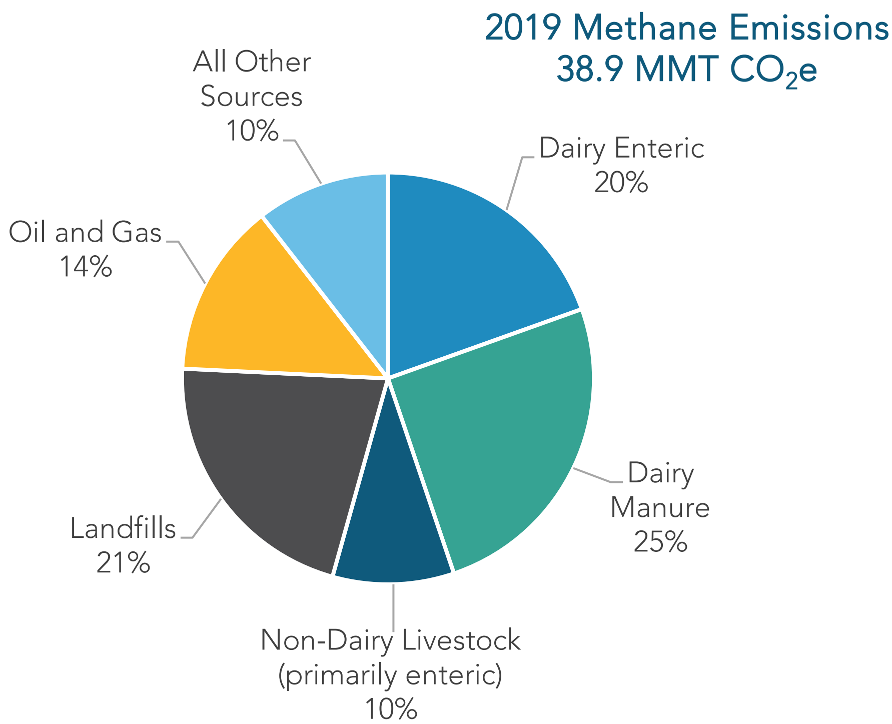
429 In contrast, the lifetime of $CO_2$ is hundreds of years. The IPCC Third Assessment Report concluded that no single lifetime can be defined for $CO_2$ because of the different rates of uptake by different removal processes. According to IPCC Fourth Assessment Report, the majority of an increase in $CO_2$ will be removed from the atmosphere within decades to a few centuries, while the remaining 20 percent may stay in the atmosphere for many thousands of years.

430 United Nations. 2021. Global Methane Assessment. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.

431 Global Methane Pledge. https://www.globalmethanepledge.org/.

432 United Nations Environment Programme. 2021. Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions?msclkid=00661370c85811eca078eb8fdbd603d1.

**Figure 4-12: Sources of California methane emissions (2019)**




Emissions from dairy and livestock operations come from two main sources: (1) enteric fermentation and (2) manure management operations, especially at dairies that employ open anaerobic lagoons that allow methane to escape into the atmosphere. Landfills, the second largest source of methane emissions, produce methane from the decomposition of organic waste. Although approximately 95 percent of all the waste that has been disposed of in the state has been deposited in a landfill that is equipped with a gas collection and control system, as required by California's Landfill Methane Regulation,[433] a portion of the methane still escapes into the atmosphere. Fugitive methane emissions can be intermittent and highly variable, both seasonally and spatially, particularly at landfills. Research has shown that landfills are complex systems and a wide range of conditions (e.g., atmospheric, operational, biological, chemical, and physical) may contribute to variability in rates of organic waste degradation, methane generation, and capture efficiency, so reducing the amount of organics deposited in landfills is critical to reducing overall landfill methane emissions. And despite the variability in individual landfill emissions, landfill gas collection and control systems remain the most effective strategy

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[433] CARB. Landfill Methane Regulation. https://ww2.arb.ca.gov/our-work/programs/landfill-methane-regulation.

for reducing methane emissions from waste once it is placed in a landfill. Non-combustion methane emissions from the oil and gas sector are the third largest source of methane emissions in California. Almost three-quarters of the methane emissions from this sector come from leaks and venting from fossil gas transmission and distribution pipelines and equipment.

## Hydrofluorocarbons

HFCs are synthetic GHGs that are powerful climate forcers. They are used mainly as refrigerants or heat transfer fluids in refrigeration, space conditioning, and heat pump equipment. Refrigerants are ubiquitous and are used everywhere from supermarkets, convenience stores, cold storage warehouses and wineries, to vending machines and residential and motor vehicle air-conditioners. Additionally, HFCs are also used as foam-blowing agents, solvents, aerosol-propellants, and fire suppressants. While HFCs remain in the atmosphere for a much shorter time than $CO_2$, the relative global warming potential (GWP) values of HFCs can be hundreds to thousands of times greater than $CO_2$. The mix of HFCs currently in use in California, weighted by usage (tonnage), have an average 100-year GWP of 1,700.[434] The average atmospheric lifetime of the mix of HFCs in use is 15 years.[435] Given the short average lifetimes, rapid reductions in HFC emissions can translate into near-term reductions in climate change effects.

As the global temperatures increase, the demand for cooling and refrigerants will continue to grow, as will the use of electric heat pumps to replace conventional fossil gas heating options. Unless addressed, continued use of high-GWP HFCs will perpetuate a feedback loop, where the cooling agents themselves cause additional warming.

In 2016, representatives from 197 nations signed the Kigali Amendment, which amended the existing Montreal Protocol (to reduce ozone-depleting substance production and consumption) to include a global phasedown in the production and consumption of HFCs beginning in 2019.[436] As of September 2022, 137 nations have either accepted, approved, or ratified the Kigali Amendment. On September 21, 2022, the U.S. Senate approved ratification of the Kigali Amendment, and it is expected that the United States

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434 CARB. 2020. *Initial Statement of Reasons: Public Hearing to Consider the Proposed Amendments to the Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Chillers, Aerosols-Propellants, and Foam End-Uses Regulation.* October 20. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2020/hfc2020/isor.pdf?_ga=2.164659835.592460318.1646664679-912670513.1542398285.

435 Zhongming, Z., et al. 2011. *HFCs: A Critical Link in Protecting Climate and the Ozone Layer: A UNEP Synthesis Report.*

436 United Nations Treaty Collection. Chapter XXVII, Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer. https://treaties.un.org/Pages/ViewDetails.aspx?src=IND&mtdsg_no=XXVII-2-f&chapter=27&clang=_en.

will soon join the 137 nations that have already ratified.[437] In the United States, Congress enacted the federal *American Innovation and Manufacturing (AIM) Act* in December 2020.[438] The AIM Act authorizes the U.S. EPA to address HFCs in several ways, including a national HFC phasedown that nearly mirrors the schedule of the global phasedown under the Kigali amendment.[439]

Nearly 90 percent of HFC emissions in California come from their use as refrigerants in the commercial, industrial, residential, and transportation sectors. The timescales over which the HFC emissions occur vary, depending on the type of application. Thus, strategies to reduce HFC emissions must be tailored by equipment type. CARB has several measures in place to tackle HFC emissions from the various sources shown in Figure 4-13 below. This includes the Refrigerant Management Program[440] that tracks and manages emissions from large commercial, industrial, and cold storage refrigeration facilities in the state. CARB has adopted regulations to reduce HFC emissions from consumer product aerosol propellants, semiconductor manufacturing, and small cans of automotive refrigerant.[441]

In 2018, California adopted HFC prohibitions via regulation and legislation for several sectors, including stationary refrigeration and foam end uses to backstop the partially vacated federal Significant New Alternatives Policy (SNAP) program.[442] Most recently, in 2020, CARB adopted additional measures that place GWP limits on refrigerants used in refrigeration and air conditioning equipment, which are the largest sources of HFC emissions, and are commonly used in residential, commercial, and industrial buildings. Additionally, CARB adopted a unique pilot program requiring the use of reclaimed refrigerant: the Refrigerant Recovery, Reclaim, and Reuse (R4) Program. The newly adopted HFC rules for the refrigeration and air conditioning sectors are the first of their kind in the nation.

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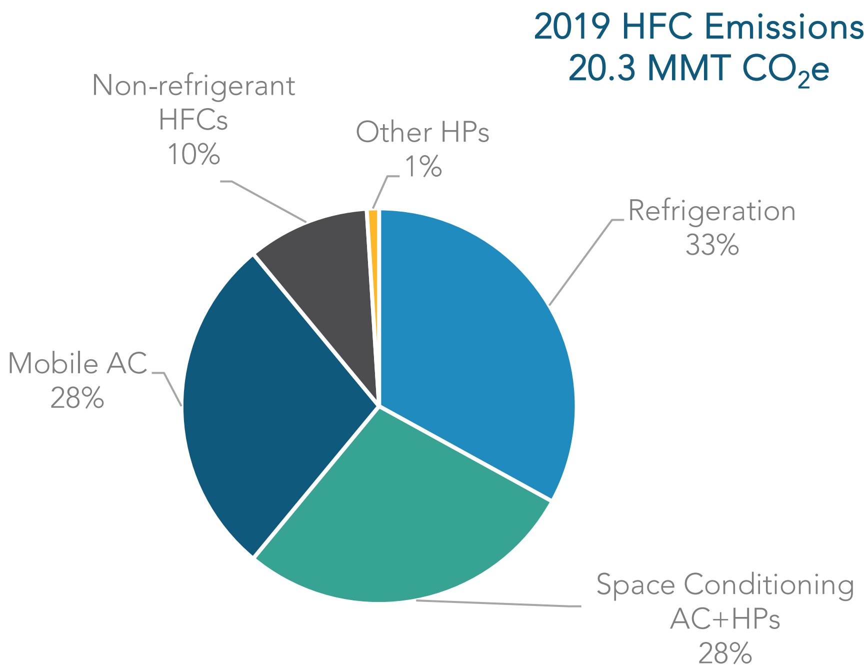
437 U.S. Ratification of the Kigali Amendment - United States Department of State. https://www.state.gov/u-s-ratification-of-the-kigali-amendment/.
438 42 U.S.C § 7675, Pub. L. 116-260, § 103. https://www.epa.gov/sites/default/files/2021-03/documents/aim_act_section_103_of_h.r._133_consolidated_appropriations_act_2021.pdf.
439 42 U.S.C § 7675, Pub. L. 116-260, § 103.
440 Cal. Code of Regs., tit. 17, §§ 95380, et seq.
441 Contained in various sections, commencing with Cal. Code of Regs., tit. 13, §§ 1900 et seq.
442 Cal. Code of Regs., tit. 17, §§ 95371, et seq.; California Cooling Act, Senate Bill 1013 (Lara, Stats. of 2018, Ch. 375, Health & Saf. Code § 39764).

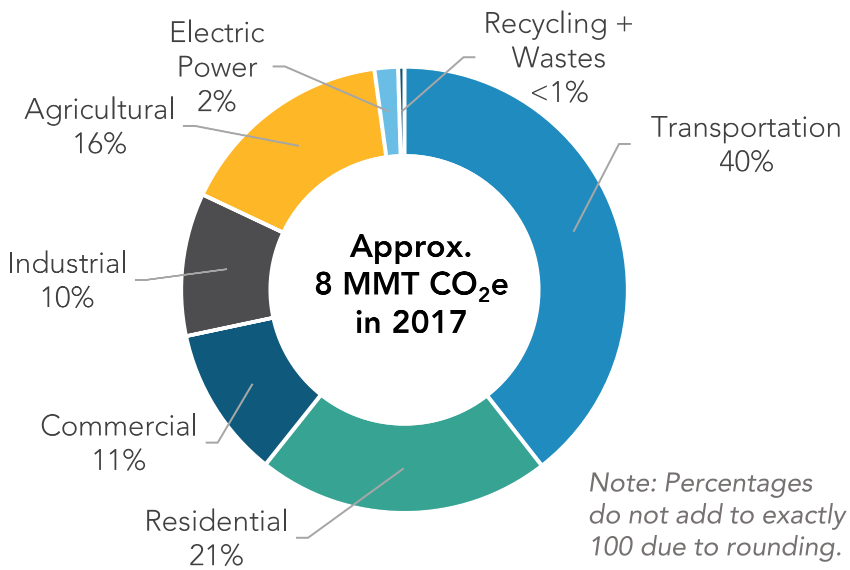
**Figure 4-13: Sources of hydrofluorocarbon (HFC) emissions (2019)**




## Anthropogenic Black Carbon

Black carbon is not included in AB 32 or the state's AB 32 GHG inventory that tracks progress toward the state's climate targets; however, it has been identified as a powerful climate forcer and is included California's Short-Lived Climate Pollutant Reduction Strategy. The majority of anthropogenic black carbon emissions come from transportation, specifically heavy-duty vehicles, and they have decreased since 2013 due to engine certification standards and in-use rules for on-road and off-road fleets, along with clean fuel requirements and incentives, including California Climate Investments and LCFS credits. Additionally, fuel combustion for residential, commercial, and industrial applications contribute significantly to overall black carbon emissions. Approximately 95 percent of residential black carbon emissions are due to wood combustion; these emissions are being reduced through programs like the Woodsmoke Reduction Program established by SB 563 (Lara, Chapter 671, Statutes of 2017). Alternatives to agricultural burning and policies that phase out agricultural burning will also result in agricultural black carbon emissions reductions. In 2021 CARB provided a preliminary estimate of 2017 black carbon emissions (Figure 4-14).[443] This estimate will be finalized as part of a future update to the Short-Lived Climate Pollutant Inventory.

**Figure 4-14: Sources of anthropogenic black carbon (preliminary 2017 estimates; AR5 100-yr GWP 900)**




## Sector Transition

California has long recognized the importance of mitigating non-combustion SLCPs and took several early action measures as part of a comprehensive, ongoing program to reduce in-state GHG emissions under AB 32. The early action measures included CARB's Landfill Methane Regulation,[444] Refrigerant Management Program,[445] and Oil and Gas Methane Regulation.[446]

### Methane

The methane abatement strategies currently in place are projected to achieve half of the methane emissions needed to meet the overall methane reduction target of SB 1383 (40 percent reduction by 2030). The reduction target translates to a limit of less than 24 $MMTCO_2e$ in 2030 (Figure 4-15). It is anticipated that, since some sectors have fewer

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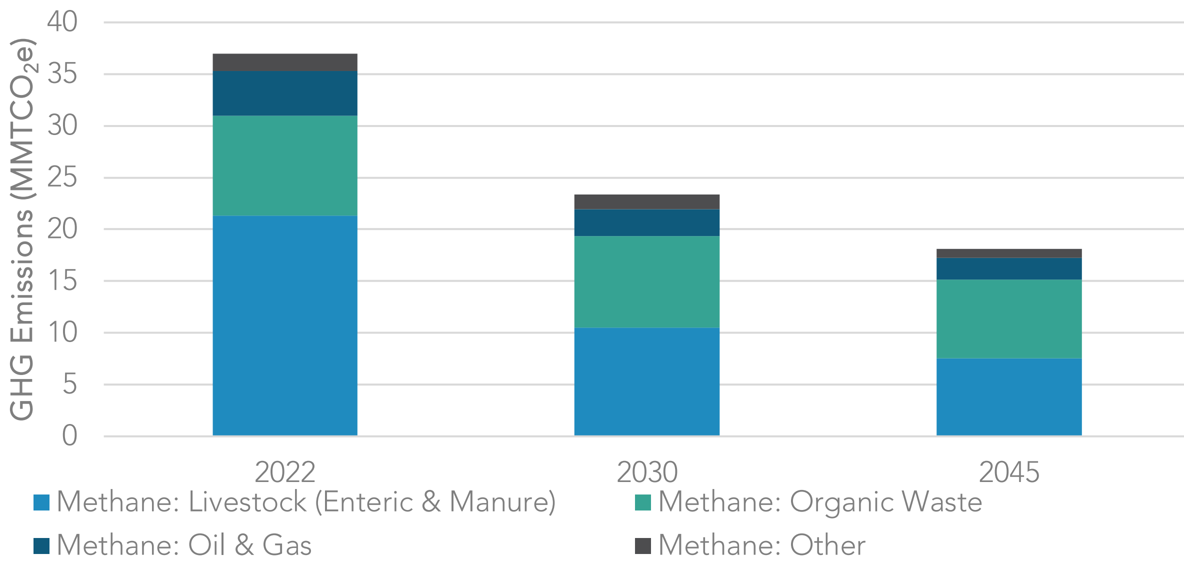
[443] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation, September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.
[444] Cal. Code of Regs., tit. 17, §§ 95460, et seq.
[445] Cal. Code of Regs., tit. 17, §§ 95380, et seq.
[446] Cal. Code of Regs., tit. 17, §§ 95665–77.

strategies that can be implemented to reduce methane in the near-term, other sectors will need to go beyond the 40 percent reduction to meet the target.

**Figure 4-15: Methane emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario**[447]




## Dairy and Livestock Methane

California is the largest dairy-producing state, home to one in five U.S. dairy cows. To date, methane emissions reductions from the dairy and livestock sector have mainly been driven by a decreasing animal population and the growing adoption of manure management strategies, including anaerobic digesters and conversion to dry manure systems and pasture systems. CARB recently completed a detailed analysis of the emission reductions expected by 2030 and the estimated additional investment needed to reach the dairy and livestock sector methane reduction target. [448]

Assuming no adoption of additional manure management and enteric mitigations strategies beyond the projects that have committed funding, and a continued annual animal population decrease of 0.5 percent per year through 2030, further reductions of approximately 4.4 $MMTCO_2e$ will be needed to achieve the 2030 methane emissions reduction target for the sector set by SB 1383. If the remaining reductions are met through

[447] The *Organic Waste* category includes methane from landfills, wastewater treatment, and compost facilities.
[448] CARB. 2021. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. June. https://ww2.arb.ca.gov/sites/default/files/2021-06/draft-2030-dairy-livestock-ch4-analysis.pdf.

a mix of dairy projects in which half are dairy digesters and half are alternative manure management projects, then it is estimated that at least 420 additional projects will be necessary. Additional emissions reductions beyond this level will likely be necessary to ensure that the overall state methane emissions reduction targets are met.

Despite the considerable methane emissions mitigation potential of enteric strategies like feed additives, little progress has been made, as few products with proven mitigation potential have become commercially available, and unlike manure management strategies, there is a lack of financial incentives for their adoption.

Market conditions favoring farm consolidation and improved production efficiencies have driven reductions in the California and U.S. dairy population over the past decade. [449] These efficiency gains have allowed California to maintain production levels despite the decreasing population. If demand for dairy and beef products remains steady or increases, continued improvements in production efficiency and adoption of effective manure management and enteric mitigation strategies will be important to support dairy and livestock methane emission reductions.

**Strategies for Achieving Success**

- Install state of the art anaerobic digesters that maximize air and water quality protection, maximize biomethane capture, and direct biomethane to sectors that are hard to decarbonize or as a feedstock for energy.
- Increase alternative manure management projects, including but not limited to conversion to “solid,” “dry,” or “scrape” manure management; installation of a compost-bedded pack barn; an increase in the time animals spend on pasture; and implementation of solid-liquid separation technology into flush manure management systems.
- Implement enteric fermentation strategies that are cost-effective, scientifically proven, safe for animal and human health, and acceptable to consumers, and that do not impact animal productivity. Provide financial incentives for these strategies as needed.
- Accelerate demand for dairy and livestock product substitutes such as plant-based or cell-cultured dairy and livestock products to achieve reductions in animal populations.
- In consideration of pace of deployment of methane mitigation strategies and the scale of complimentary incentives, consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in SB 1383 are met.

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[449] MacDonald, James M., Jonathan Law, and Roberto Mosheim. 2020. *Consolidation in U.S. Dairy Farming.* ERR-274. July. https://www.ers.usda.gov/webdocs/publications/98901/err-274.pdf.

## Landfill Methane

Achieving the 75 percent organic waste disposal reduction target[450] of SB 1383, and maintaining that level of disposal in subsequent years, would bring annual landfill emissions in 2030 to just below the 2013 baseline. Annual methane emissions will be higher through 2030 than originally anticipated by the SLCP Strategy because the state did not achieve the anticipated reductions in organic waste disposal of 50 percent below 2014 levels by 2020. SB 1383 prohibited the organic disposal regulations from taking effect until 2022,[451] and, as a result, emissions have continued to increase.

Due to the multidecadal time frame required to break down landfilled organic material, the emissions reductions from diverting organic material in one year are realized over the course of several decades. For example, one year of waste diversion in 2030 is expected to avoid 8 $MMTCO_2e$ of landfill emissions, cumulatively, over the lifetime of that waste's decomposition.[452] Near-term diversion efforts are critical to avoid locking in future landfill methane emissions.

CalRecycle's 2020 report, *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals,*[453] estimated that 8 million short tons of composting and anerobic digestion capacity will be needed to manage organic wastes, above the existing and new capacity expected to be available by 2025. The 2019 report, *Co-Digestion Capacity in California,*[454] from the State Water Resources Control Board estimated that at least 2.4 million tons of digester capacity is available at urban wastewater treatment plants if sufficient incentives or funding for collection, receiving, and processing operations are provided to enable utilization of this capacity. The CPUC approved a decision in February 2022 implementing the biomethane procurement program, which will require investor-owned utilities by 2025 to procure 17.6 billion cubic feet (BCF) of biomethane produced from organic wastes to support the landfill disposal reduction and SLCP target and reduce fossil gas reliance for

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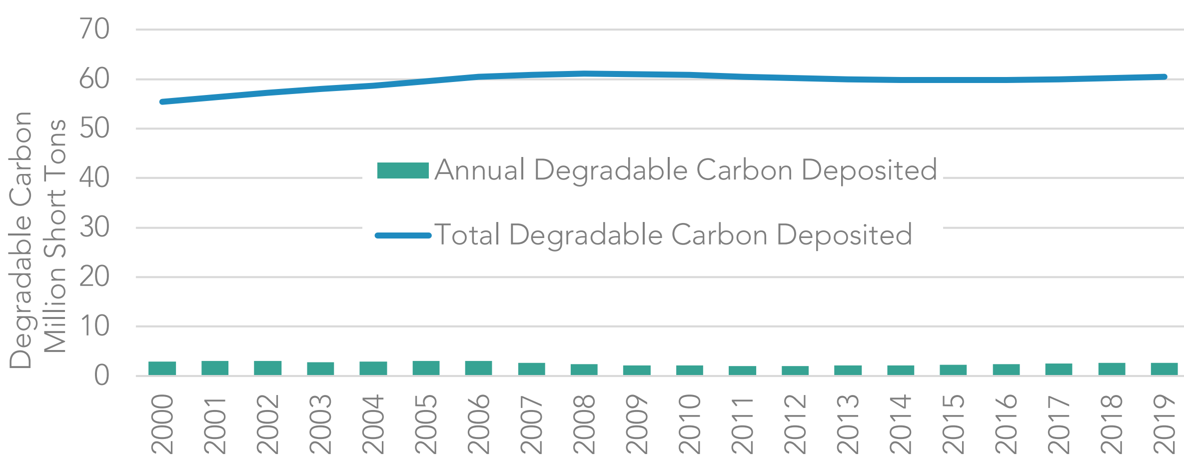
[450] The target is from 2014 levels by 2025.
Public Resources Code, § 42652.5. CalRecycle approved the SLCP: Organic Waste Reductions regulations (*https://calrecycle.ca.gov/organics/slcp/*) in 2020 and began implementing them in January 2022. These regulations are designed to achieve the 2025 disposal reduction and edible food recovery targets.
[452] The life cycle emissions reduction is based on anticipated diversion of 27 million short tons of organic waste from CalRecycle (2020) Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals (*https://www2.calrecycle.ca.gov/Publications/Details/1693*). Under CalRecycle's SLCP regulations, an alternative to landfill disposal must achieve a life cycle GHG reduction of 0.3 $MTCO_2e$ per short ton of waste diverted.
[453] CalRecycle. 2020. *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals.* *https://www2.calrecycle.ca.gov/Publications/Details/1693*.
[454] State Water Resources Control Board. 2019. *Co-Digestion Capacity in California.* *https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf*.

residential and commercial customers.[455] Additionally, the organic waste stream includes more than one million tons of edible food that could be recovered before it enters the waste stream through food rescue programs that combat hunger in communities throughout California.

While reducing organic waste disposal is the most effective means of achieving reductions in waste sector methane, strategies to reduce emissions from waste already in place in landfills also will play a role in achieving near-term reductions. As Figure 4-16 shows, the total degradable carbon (a measure of the amount of waste with potential to generate methane) that is accumulated from waste deposited in previous years is over 20 times greater than the amount added each year. This illustrates that even if we were able to entirely phase out landfilling of organic waste today, the existing waste in place at landfills would continue to generate methane for decades into the future.

Through a combination of improvements in operational practices, use of lower permeability covers, advanced landfill gas collection systems, and increased monitoring to detect and repair leaks, it is estimated that a direct emission reduction of 10 percent is achievable across the state's landfills by 2030. Technologies to utilize landfill gas efficiently can contribute further emission reductions in the energy sector.

**Figure 4-16: Degradable carbon deposited in landfills**




### Strategies for Achieving Success

- Maximize existing infrastructure and expand it to reduce landfill disposal, with strategies including composting, anaerobic digestion, co-digestion at wastewater treatment plants, and other non-combustion conversion technologies.

455 CPUC. 2022. Decision 22-02-025.

- Expand markets for products made from organic waste, including through recognition of the co-benefits of compost, biochar, and other products.[456]
- Recover edible food to combat food insecurity.
- Invest in the infrastructure needed to support growth in organic recycling capacity.
- Utilize existing digesters at wastewater treatment facilities to rapidly expand food waste digestion capacity.
- Direct biomethane captured from landfills and organic waste digesters to sectors that are hard to decarbonize.
- Implement improved technologies and best management practices at composting and digestion operations.
- Reduce emissions from landfills through improvements in operational practices, lower permeability covers, advanced collection systems, and technologies to utilize landfill gas.
- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks, improve understanding of the factors that lead to better capture efficiency, and explore new technologies and practices that can reliably improve methane control at landfills.

## Upstream Oil and Gas Methane Reduction

For oil and gas production, processing, and storage, California is currently on track to achieve a 41 percent reduction in methane emissions by 2025 relative to 2013. The additional reductions needed to meet the 2030 target may be achieved by implementing additional regulatory requirements to further reduce intentional venting of fossil gas from equipment. If necessary, additional reductions from transmission and distribution facilities may be achieved by requiring the utilities to increase inspection and repair activities or further reduce emissions from pipeline blowdowns by implementing methods such as using portable compressors, using plugs to isolate sections of pipelines, flaring vented gas, routing gas to fuel gas systems, and installing static seals on compressor rods. Advances in methane detection technologies (e.g., satellites equipped to detect large methane sources) may also help to identify and mitigate methane emissions quickly across the oil and gas sector.

As California transitions away from fossil fuels, in-state oil and gas production will likely decline. This could result in an increase over time in the number of long-term idle and orphan wells (idle wells lacking a financially solvent, responsible owner) in the state. While California has regulations aimed at helping ensure operators manage their idle wells,

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[456] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.4. *finalejacrecs.pdf (arb.ca.gov)*.

there could likely be an increase in California's orphan well population. Plugging all orphan wells, of which there are currently over 5,000, could take decades due to the limited resources California has for orphan well plugging. The benefits from plugging wells include methane emission reductions and job creation; employment gains from well plugging and site remediation activities could help temporarily offset job losses from the oil and gas industry. The California Council on Science and Technology's 2018 report on orphan wells, *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells,*[457] found that the potential cost to the state of plugging current orphan wells could be approximately $500 million, and the cost of plugging all active and idle wells could total over $9.1 billion. As oil and gas production in California declines due to reduced demand for fossil fuels, additional funding will likely be needed to cover the costs of plugging wells that have no viable operator.

**Strategies for Achieving Success**

- Mitigate emissions from leaks by regular leak detection and repair (LDAR) surveys at all facilities.
- Replace high emitting equipment with zero emission alternatives wherever feasible.[458]
- Have CARB and CalGEM lead a Task Force to identify and address methane leaks from oil infrastructure near communities.
- Pursuant to SB 1137, develop leak detection and repair plans for facilities in health protection zones, implement emission detection system standards, and provide public access to emissions data.
- Minimize emissions from equipment that must vent fossil gas by design (e.g., fossil gas powered compressors).
- Install vapor collection systems on high emitting equipment.
- Phase out venting and routine flaring of associated gas (gas produced as a by-product during oil production).
- Continuous ambient monitoring at fossil gas underground storage facilities to quickly detect large methane sources.
- Reduce pipeline and compressor blowdown emissions.

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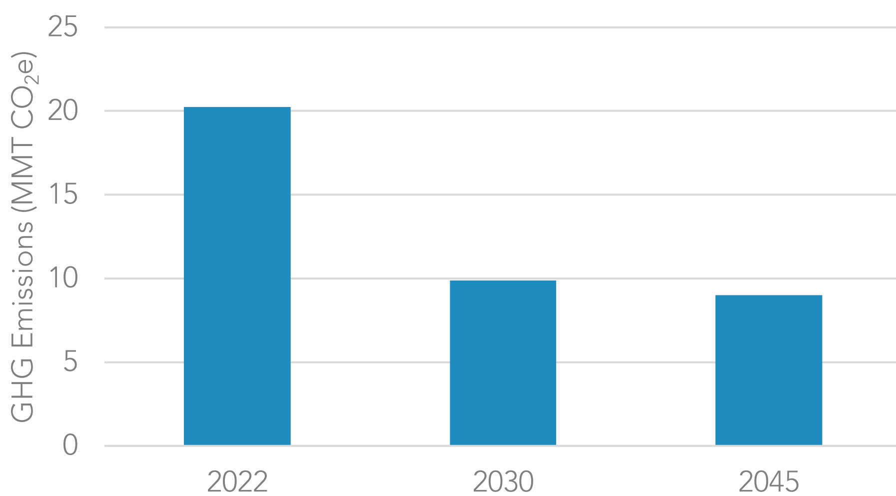
[457] The California Council on Science and Technology. 2018. *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells.* https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf.
[458] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, P5. finalejacrecs.pdf (arb.ca.gov).

- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks.[459]

## Hydrofluorocarbons

In California, all the HFC measures currently in place will help achieve more than 70 percent of the reductions needed to achieve the 2030 HFC goal and provide very significant emissions reductions by 2045 and beyond. However, new targeted measures will be needed to maintain the pace of reductions, as demand for technologies that currently predominantly use high-GWP refrigerants is anticipated to grow. Despite decarbonization efforts, high-GWP HFCs are expected to be among the last remaining persistent GHG emission sources, as shown in Figure 4-17.[460]

**Figure 4-17: Hydrofluorocarbon emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario**




HFC emissions from new and existing sources should be addressed in tandem with building decarbonization efforts to maximize reductions.[461] As buildings are electrified in an effort to decarbonize them, the use of heat pumps for space conditioning, water heaters, and clothes dryers is expected to increase significantly. Heat pumps, while using

[459] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, CC17. finalejacrecs.pdf (arb.ca.gov).
[460] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.
[461] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. finalejacrecs.pdf (arb.ca.gov).

electricity, not fossil gas, currently rely predominantly on high-GWP refrigerants. Very low- or no-GWP technologies and solutions are either available or emerging for various heat pump technologies, and likely to develop further as international efforts to mitigate HFCs continue. However, most of these technologies are still nascent in the United States. In addition, some of the alternatives cannot be used until California building codes are updated, which is currently expected at the earliest in mid-2024 for some technologies based on the recently adopted provisions in AB 209[462] requiring the California Building Standards Commission to adopt the latest safety standards for refrigerant containing equipment into California's building codes. The current updates to the building codes will allow the use of many refrigerants with lower GWPs than HFCs currently in use. However, additional building code updates are needed to expand the choices of ultra-low-GWP alternatives, and that will need to happen in the next few years. The adoption of low-GWP refrigerants must occur in parallel with building decarbonization efforts; without such efforts, the vast GHG benefits of the latter will be partially offset, and the proportion of HFC emissions from buildings will continue to grow.

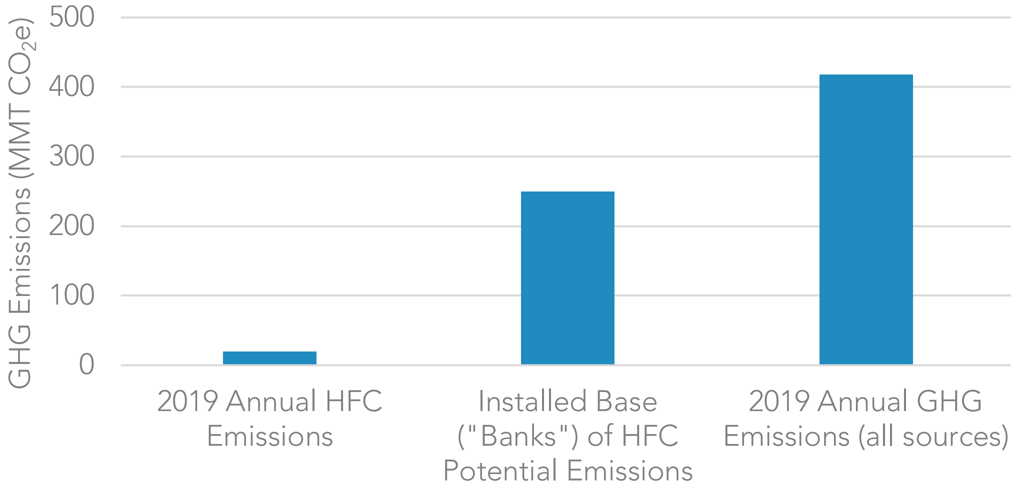
Leaks from existing air conditioning and refrigeration equipment are a major source of statewide and global HFC emissions. Once installed, refrigeration and air conditioning equipment can stay in place for decades, while leaking refrigerants into the atmosphere. This makes it very important that new installed equipment use refrigerants with a GWP as low as possible. The refrigerants inside existing equipment are sometimes collectively referred to as the *installed base* or *banks* of potential HFC emissions. If released spontaneously, the existing HFC banks would equal 60 percent of all annual statewide GHG emissions in California, as illustrated in Figure 4-18.[463]

The sales prohibitions on newly produced refrigerants set forth in SB 1206 (2022) and the national/international HFC phasedown will help in reducing HFC emissions from existing equipment by restricting the supply of and increasing the value of existing high-GWP HFCs, thus enabling a circular economy. In the 2022–2023 state budget, CARB received $45 million in incentive funding for climate-friendly refrigerant technologies; this funding will be critical in shifting the market toward the best available refrigerant technologies in various sectors.

[462] AB 209: Energy and climate change. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209.

[463] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation. September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.

**Figure 4-18: Potential emissions from refrigerants in existing equipment**




**Strategies for Achieving Success**

- Expand the use of very low- or no-GWP technologies in all HFC end-use sectors, including emerging sectors, like heat pumps for applications other than space conditioning, to maximize the benefits of building decarbonization.[464]
- Convert large HFC emitters such as existing refrigeration systems to the lowest practical GWP technologies.[465]
- Prioritize small-scale and independent grocers serving priority populations in addressing existing "banks" of high-GWP refrigerants.[466]
- Improve recovery, reclamation, and reuse of refrigerants by limiting sales of new or virgin high-GWP refrigerants and requiring the use of reclaimed refrigerants where appropriate.[467]
- Assist low-income and disadvantaged communities in obtaining low-GWP space conditioning units to protect vulnerable communities from heat stress and wildfire smoke.[468]

[464] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. *finalejacrecs.pdf (arb.ca.gov)*.
[465] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. *finalejacrecs.pdf (arb.ca.gov)*.
[466] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT5 and JT6. *finalejacrecs.pdf (arb.ca.gov)*.
[467] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT1. *finalejacrecs.pdf (arb.ca.gov)*.
[468] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF28, JT5, and JT6. *finalejacrecs.pdf (arb.ca.gov)*.

- Accelerate technology transitions in California and the U.S. overall by collaborating with international partners committed to taking action on HFCs under the Kigali Amendment to the Montreal Protocol; this includes addressing barriers to adoption of very low- or no-GWP refrigerant technologies such as high upfront costs, shortage of trained technicians, and lag in updating safety standards and building codes.

## Anthropogenic Black Carbon

Significant progress has been made since 2013 to reduce anthropogenic black carbon emissions, primarily from decreased combustion of distillate fuels in the agricultural sector, as well as improvements to provide cleaner, on-road combustion technologies. Under current strategies, anthropogenic black carbon from transportation is expected to be reduced by over 60 percent in 2030. Continued reductions in combustion emissions across all sectors from both the state's climate and air quality programs will also help reduce anthropogenic black carbon emissions going forward.

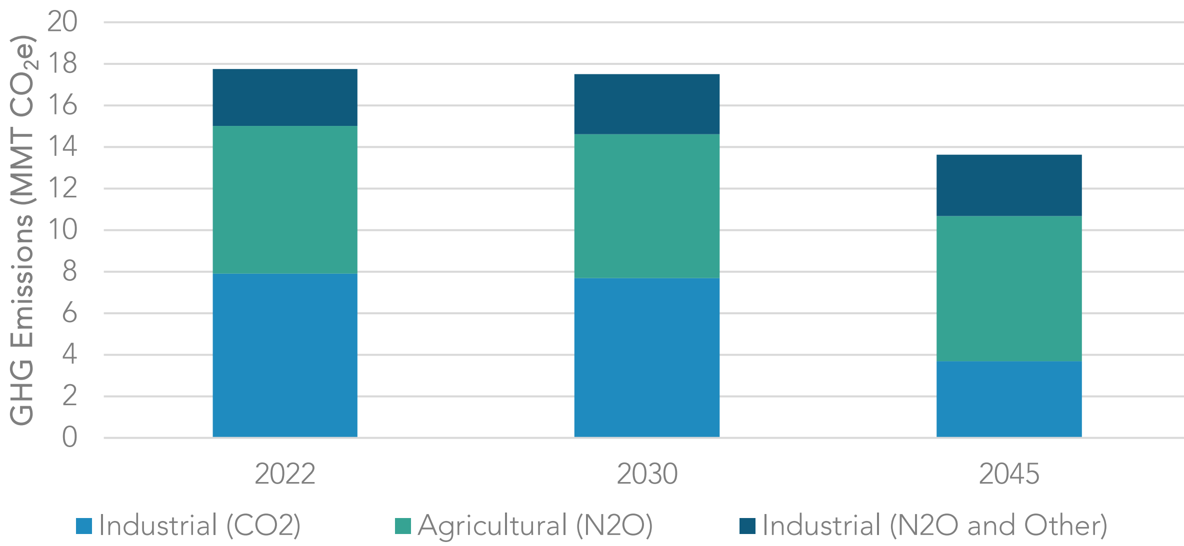
**Strategies for Achieving Success**

- Reduce fuel combustion commensurate with state's climate and air quality programs, particularly from reductions in transportation emissions and agricultural equipment emissions.[469]
- Invest in residential woodsmoke reduction.

In addition to SLCP emissions, some remaining non-combustion emissions are anticipated to persist in the coming decades, as shown in Figure 4-19. These include $CO_2$ from industrial processes such as cement manufacturing, oil and gas extraction, and geothermal electric power; $N_2O$ from wastewater treatment, fertilizers, and livestock manure applied to agricultural soils; and other industrial, non-HFC GHG emissions.

[469] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A and Appendix A (Table Summary of Direct Emission Reduction Strategies). "Emissions reductions from energy consumed by California's agricultural sector, including post-harvest processing, use of tractors and other farm equipment, and water import and irrigation." *finalejacrecs.pdf (arb.ca.gov)*.

**Figure 4-19: Remaining non-combustion emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario**




## Natural and Working Lands

California's natural and working lands (NWL) cover approximately 90 percent of the state's 105 million acres,[470] and include forests, grasslands, shrublands and chaparral, croplands, wetlands, sparsely vegetated lands, and the green spaces in urban and built environments. These lands include California Native American tribes' ancestral and cultural lands, parks and green spaces in our cities and communities, and the waters and the iconic landscapes we know and love. The diverse landscapes and biodiversity found throughout California's NWL provide a multitude of benefits to the people of California, including clean water, clean air, biodiversity, food, economic prosperity, recreational opportunities, continuation of traditional tribal ways of life, mental health benefits, and many others.

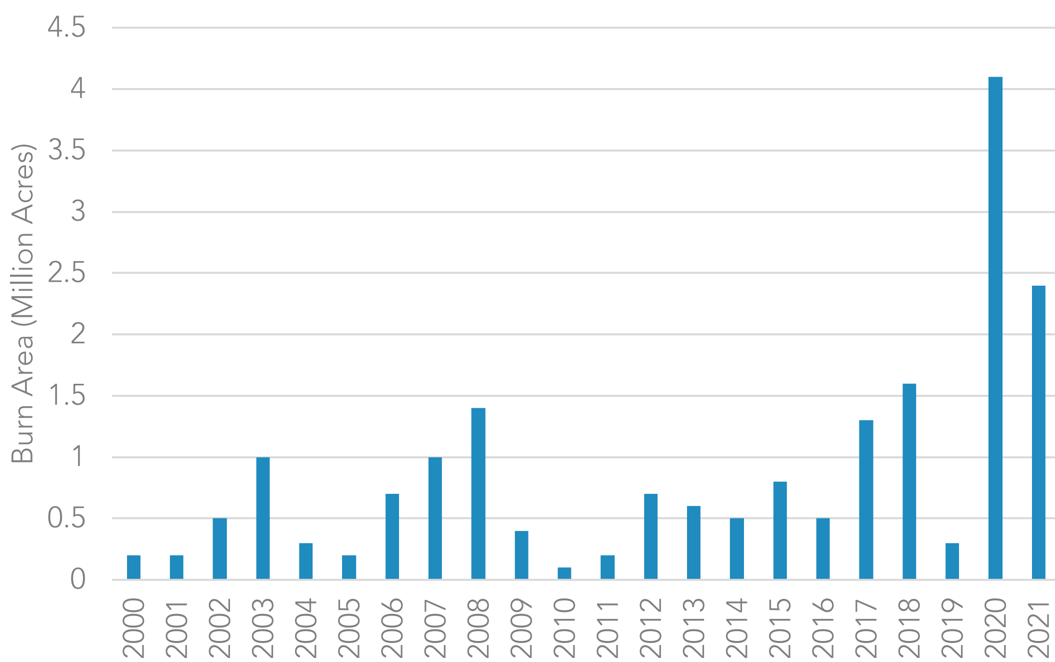
Our lands are a critical sector in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric $CO_2$. Healthy lands also can reduce emissions of powerful SLCPs, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Creation of healthy lands through

[470] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

multi-benefit and mitigation measures can also support tribal and local traditional lifeways. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts.

Climate change impacts have become more apparent in recent years and are having significant effects on communities throughout the state. One of these impacts is the much more frequent occurrence of unusually large, high-severity wildfires, which are being driven by climate change and by a recent history of fire-exclusion and land management practices that have resulted in forests with high levels of biomass. These recent large and high-severity wildfires have resulted in a significant amount of burned acreage and emissions in California (Figure 4-20).[471]

**Figure 4-20: Acreage of burned wildland vegetation area**




These wildfires deviate from the lower-severity fires that previously occurred at frequent intervals, around which California's forests evolved. As climate change accelerates, these large, uncharacteristic wildfires are likely to become more common and impact more of our landscapes. Climate change is also expected to have other significant effects on our lands, including more extreme droughts, floods, extreme heat, and the spread of invasive aquatic and terrestrial species, pests, diseases, and parasites. These impacts can lead

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[471] CARB. 2022. Wildfire Emission Estimates for 2021. https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/Wildfire%20Emission%20Estimates%202000-2021.pdf.

to negative feedback loops on human and ecological health; for example, increasing the spread of invasive species can lead to increases in pesticide use, if not managed through regulation or mitigation, which can pose risks to human health and the environment.

California's approach to climate action in the NWL sector is not solely focused on maximizing carbon stocks but instead on supporting carbon management that holistically fosters ecosystem health, resilience, provision of overall climate function, and other co-benefits.

Natural systems operate on a longer timescale than the energy and industrial sectors, and benefits from climate action on our lands can take decades to accrue. Scaling climate smart land management in California requires taking action now and playing the "long game" by establishing and maintaining consistent, patient approaches and programs.

## Landscapes

For the first time, this Scoping Plan includes modeling for the NWL sector. The focus of the initial modeling is limited to seven land types that align with the those in the NWL Climate Smart Strategy.[472] Work will continue to incorporate more landscapes and management practices into the modeling over time. The initial landscapes included in the modeling for this Scoping Plan are:

- Forests
- Shrublands and Chapparal
- Grasslands
- Croplands
- Wetlands
- Developed Lands
- Sparsely Vegetated Lands

Each of these land types are a key component to the state's approach to increasing climate action in the NWL sector, as called for in Executive Order N-82-20 and AB 1757.[473] The Executive Order directs CARB to update the target for this sector in support of carbon neutrality by 2045 as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy. AB 1757 calls for the development of an

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[472] CNRA. 2022. *Natural and Working Lands Climate Smart Strategy. Appendix B.* https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Appendix-B_04132022_ada.pdf.

[473] AB 1757 California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1757.

ambitious range of targets for the NWL sector to be integrated into the Scoping Plan and other state policies. It directs CARB and CNRA to work closely together to update the NWL Climate Smart Strategy, and establish an expert advisory committee to inform and advise on NWL modeling, targets, and implementation strategies.[474] Additionally, in 2021, the governor signed SB 27[475] (Skinner, Chapter 237, Statutes of 2021) into law. It directed CARB to establish $CO_2$ removal targets for 2030 and beyond and take into consideration the NWL Climate Smart Strategy. The governor's Executive Order, AB 1757, and SB 27 go beyond previous direction from the Legislature and past administrations. These directives emphasize the importance of quantifying land-based carbon both statewide,[476] and in programs and policies,[477] setting targets[478] for NWL to support the state's climate objectives, and advancing land management actions[479] that support the health and resiliency of these lands.

Blue carbon (also known as carbon captured and held in coastal vegetation and soils, such as seagrasses, seaweeds, and wetlands)—is also important to consider as we look at long-term climate goals. While this landscape is not currently covered by IPCC inventory guidelines or included in California's NWL Inventory, the United States was the first nation to include blue carbon in its national GHG emissions inventory. California's Ocean Protection Council and San Francisco Estuary Institute are partnering to create a new coastal wetlands, beaches, and watersheds inventory. CARB staff will utilize information from this effort and assess other available data to evaluate how this landscape may be integrated into our efforts in the future as more data become available.[480]

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474 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N20. [finalejacrecs.pdf (arb.ca.gov)](#).

475 SB 27 Carbon sequestration: state goals: natural and working lands: registry of projects. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB27.

476 SB 859 Public resources: greenhouse gas emissions and biomass (SB 859, Committee on Budget and Fiscal Review, Chapter 368, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB859.

477 SB 1386. Resource conservation: working and natural lands. (SB 1386, Chapter 545, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1386.

478 CARB. 2017. 2017 Climate Change Scoping Plan Update. Board Resolution 17-46. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2017/res17-46.pdf.

479 Executive Department. State of California. EO B-52-18. https://www.ca.gov/archive/gov39/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf.

480 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. finalejacrecs.pdf (arb.ca.gov).

## Trends of Carbon on Landscapes

CARB currently tracks the carbon stock changes though the Inventory of Ecosystem Carbon in California's Lands[481] (NWL Inventory), which is summarized in Chapter 1. The NWL Inventory is a key tool for tracking changes in carbon stocks across the state, and it will serve as the inventory of record for this sector, tracking sector-wide progress toward the target. The NWL Inventory provides a retrospective snapshot of the status of California's lands, and captures the gains or losses of carbon stocks that occur over time. In addition to tracking carbon stock changes, the NWL Inventory is an important tool for understanding the impacts of our efforts to increase climate action in this sector (such as those identified in this Scoping Plan and the NWL Climate Smart Strategy) on NWL carbon stocks. The inventory is also used as the foundation for Scoping Plan scenario modeling and target setting.

CARB's inventory shows that carbon stocks decreased in NWL lands from 2001 to 2011, releasing more carbon than they were storing, and then increased slightly from 2012 to 2014.[482] These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon, and the importance of looking at NWL data and trends over multiyear and multidecadal time periods, as opposed to looking only at annual changes. This movement is part of the Earth's carbon cycle, where carbon transfers between the land, ocean, and atmosphere. As part of the carbon cycle, over decades or centuries, fire and plant respiration and decomposition move carbon from the land to the atmosphere, while plant growth and other processes move carbon from the atmosphere to the land. Emissions from fossil-fuel combustion are contributing to putting this cycle out of balance.

Additionally, some historic land management practices that have resulted in the loss of carbon from the soil are also contributing to the atmospheric rise of $CO_2$ while simultaneously exacerbating the imbalance of the water cycle, which is influenced by and linked to the carbon cycle. These emissions are also contributing to a feedback loop for California's lands: as $CO_2$ emissions accumulate in the atmosphere—and California experiences more warming, extreme heat events, and droughts—the risk and intensity of carbon losses also increases, which in turn transfers more carbon from the land to the atmosphere. And because forests and shrublands comprise approximately 85 percent of the carbon stocks in California, management strategies and disturbances in forest and

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[481] CARB. *An Inventory of Ecosystem Carbon in California's Natural & Working Lands.* 2018 Edition. [nwl_inventory.pdf (ca.gov)](). Accessed 3/2/2022.

[482] These trends are consistent estimates in the most recent AB 1504 reporting period.

shrubland carbon play an important role in determining whether California's lands are providing either net carbon sequestration or net emissions on an annual basis.

The gains and losses of carbon on our lands will fluctuate in the future; what is important is to restore carbon in places where it has been lost and reduce large carbon losses on our NWL through active, attentive, and adaptive management. For additional details on the nexus between NWL and GHGs, see pages 5–6 of the NWL Climate Smart Strategy.

## Goals and Accelerating Nature-Based Solutions

The state's climate mitigation targets are traditionally identified by individual years, (i.e., tons of GHG emissions in 2020 or 2030). However, because NWL processes fluctuate year to year and because it can sometimes take decades for climate action to fully impact carbon in NWL, it is important to consider the statewide, long-term trends of carbon stock change when identifying how this sector contributes to California's pathway to achieving carbon neutrality. Tracking carbon stock change over a multi-decadal period is the best way to assess the full direct impact climate action has on carbon storage. Such an approach filters out fluctuations from year-to-year weather variations and multi-year natural climate cycles, such as El Niño patterns.

Current data sources and methods allow us to track only certain carbon stocks that exist on NWL. For target tracking to be successful, each carbon pool must be inventoried using a methodology that can detect changes due to management and climate change. Certain carbon pools lack the scientific data and methodologies necessary for target-setting and tracking. For example, soils in forests, shrublands, and grasslands are not included in the Scoping Plan carbon stock target because, currently, there is no way to track statewide soil carbon through time in a way that would capture the effects of increased climate action and climate change.

When considering how NWL contribute to the state's goal of carbon neutrality, all lands' carbon stock gains and losses must be considered, and the Scoping Plan target is set in these terms. It is not sufficient to aggregate climate benefits only within areas where projects, management, or climate action occur. Much of the state does not receive active or quantifiable management, but these areas still contribute to the state's overall carbon stock change and GHG emissions. To incorporate the entire carbon balance toward true carbon neutrality, the Scoping Plan target is set in terms of carbon stock change across the entire state. This incorporates all lands that both receive and do not receive active management, and includes the end result of all sequestration, emissions, and other changes to carbon on the landscape.

However, carbon stock change is not equivalent to emissions. Currently, the data and emission quantification science is not sufficient to enable inventories to comprehensively track all NWL emissions in a way that would enable us to set an NWL target in terms of statewide emissions and sequestration. There is a great need, across the entire NWL sector statewide, for more empirical data, science, and tools to track all carbon stocks across each carbon pool, and to begin to track emission and sequestration rates. As California implements AB 1757, there is an opportunity to update the data, science, and tools to enable this level of tracking and target setting in the future.

As outlined in Chapter 2, California is projected to lose carbon stocks over the coming decades, but this Scoping Plan analysis also shows that increasing the pace and scale of climate smart land management in California will reduce the carbon stock losses and GHG emissions from the NWL sector. In response to EO N-82-20 and AB 1757, the proposed target for NWL is shown in Table 4-1.

**Table 4-1: Scoping Plan modeled target for NWL, based on increasing action on NWL**

| | Total Carbon Stock % Change from 2014 |
|---|---|
| **2045** | -4 |

Achieving this target will require significant expansion of the pace and scale of climate action on California's NWL, including the following:

- Increasing climate smart forest, shrubland, and grassland management to at least 2.3 million acres a year—an approximate 10x increase in management from current levels.
- Increasing climate smart agricultural practices by at least 78,000 acres adopted a year, annually conserving at least 8,000 acres a year of croplands, and increasing organic agriculture to comprise at least 20 percent of cultivated acres in California by 2045—an approximate 7.5x increase in healthy soils practices from previous levels and a 2x increase in total acres of organic agriculture.
- Increasing annual investment in urban trees in developed lands by at least 200 percent above historic levels and establishing defensible space on all parcels by 2045.
- Restoring at least 60,000 acres, or approximately 15 percent of all Sacramento–San Joaquin River Delta (Delta) wetlands, by 2045.
- Cutting land conversion of deserts and sparsely vegetated landscapes by at least 50 percent annually from current levels, starting in 2025.

If the carbon stock target above is met, and the management actions above are implemented, the modeling for NWL indicates that California's lands will be a net source of emissions, producing approximately 7 $MMTCO_2e$ of average annual emissions.

Additional climate smart management practices and additional landscapes, such as those included in the Climate Smart Strategy and discussed below in Additional Management Strategies, have the potential to increase carbon stocks and reduce GHG emissions from NWL beyond the levels modeled for this Scoping Plan.

The purpose of the NWL target and the above estimated outcomes is to provide a numerical guide that can support the state's efforts to accelerate both near-term and long-term climate action on California's lands, prioritizing durable solutions that deliver multiple outcomes. Taking these actions over the coming decades will reduce the potential carbon losses from NWL, reduce GHG emissions from some landscape types (such as croplands and Delta wetlands), and support sequestration of GHGs from NWL between 2025 and 2045. These actions will also deliver significant benefits to Californians beyond advancing our climate goals, such as reducing wildfire emissions and their associated health impacts, increasing habitat for biodiversity, reducing urban heat island effects, reducing harmful pesticide exposure, expanding economic opportunities, and others. Additional information on several economic and health outcomes from the Scoping Plan Scenario is included in Chapters 2 and 3.

Statewide planning and target setting for the NWL sector will only create meaningful change if followed by effective on-the-ground implementation. State government cannot accomplish this implementation alone. Effective large scale climate action is dependent on partnerships among tribal, federal, state, regional, and local partners, and across governmental, private, nonprofit, and commercial sectors. The NWL sector of the Scoping Plan sets a carbon target with climate action recommendations that can be used to achieve the quantified carbon, health, and economic outcomes. Implementation of these actions must be led by local or regional partnerships that plan and execute projects appropriate to the specific conditions. The technical expertise and local knowledge of land managers and stewards in all sectors must be elevated to ensure relevant, efficient, and effective climate action.

Implementation of climate action should contribute to state targets, maximize local benefits, and alleviate environmental injustices and other social inequities. On-the-ground action is largely executed and managed by local and regional actors, but state government agencies must support communities across the state in implementing nature-based climate solutions that address statewide objectives, such as the Scoping Plan carbon target. This includes providing resources and developing frameworks, while greatly increasing capacity and technical assistance to assist and empower local partners. Examples of how this can be done are the Regional Forest and Fire Capacity Program within the forestry sector, the UC Cooperative Extension in the agricultural and forestry sectors—as well as the work of the state's 10 regional Conservancies. These programs provide strong examples to emulate as they facilitate statewide coordination, and information and resource transfer from the state to the regional and local levels. The Regional Forest and Fire Capacity Program provides funding for local and regional groups to build their organizational capacity to plan and implement wildfire and forest management projects that are informed by their own local expertise. The UC Cooperative Extension is an example of how the state provides technical assistance to local landowners and community organizations, helping them apply the latest science-based management strategies to their lands. California's regional Conservancies play a pivotal role in implementing regional conservation, restoration, and land management efforts through activities such as grant funding, science generation, and planning assistance.

The state also has identified the need to incorporate and elevate traditional indigenous knowledge into climate action on the regional and local scales. Accomplishing this requires close partnerships with tribes for mutual knowledge and resource sharing, while protecting culturally sensitive knowledge and resources. As Tribes are sovereign nations with specialized cultural knowledge and experience in managing lands, climate action on these lands that contribute to the State of California's climate targets can only be accomplished with the full participation and under the leadership of the Tribes that govern those lands.

### Strategies for Achieving Success: Crosscutting Items for all NWL

- Implement AB 1757 and SB 27.
- Implement the Climate Smart Strategy.
- Accelerate the pace and scale of climate smart action, consistent with the management levels identified above, as part of a collective effort between federal, state, private, nonprofit, and individual land managers.
- Prioritize and practice equity, including through meaningful community engagement and prioritizing implementation of nature-based solutions that benefit the communities most vulnerable to climate change.[483]
- Advance multi-benefit, collaborative, landscape-level approaches that engage communities and landowners, and incorporate adaptive managements.
- Consult and partner with California Native American tribes to increase co-management and tribal management authority; restore, protect, and enhance natural cultural resources, traditional foods, and cultural landscapes; respect tribal sovereignty; and support tribes' implementation of tribal expertise and Traditional Ecological Knowledge and cultural easements.[484]

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[483] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. finalejacrecs.pdf (arb.ca.gov).

[484] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N1, N6, N16, N17, N18. finalejacrecs.pdf (arb.ca.gov).

- Leverage existing innovative financial and market mechanisms, and explore new ones, between the public, private, and philanthropic sectors to secure funding of climate smart land management.
- In partnership with communities, tribes, and the private sector, expand and develop new infrastructure for manufacturing and processing of climate smart agricultural and biomass products.
- Leverage and support technical assistance providers: such as the UC Cooperative Extension and California's 98 Resource Conservation Districts, that have track records of providing technical assistance to local landowners and implementing agriculture, forestry, natural resource management, and restoration projects across the state.
- Establish and expand mechanisms that ensure NWL are protected from land conversion and parcelization (e.g., conservation easements or Williamson Act), in line with the strategies outlined in CNRA's Pathways to 30x30 California.[485,486] Pair land conservation projects with management plans that increase carbon sequestration, where feasible.
- Increase opportunities for private and philanthropic investments in nature-based climate solutions, utilizing existing voluntary and compliance carbon markets, existing state and local programs, and the California Carbon Sequestration and Climate Resiliency Project Registry established pursuant to SB 27.
- Expand monitoring and tracking of management actions and outcomes consistent with the tracking and monitoring recommendations of the Climate Smart Strategy.

## Forests, Shrublands, and Chaparral

At roughly 29 million acres, forests cover 27 percent of California. Shrublands and chaparral cover 31 percent of the state; roughly 33 million acres. Both types are distinct, with their own ecological dynamics and management strategies, and are modeled within a single model that is calibrated to treat them uniquely.

Together, forests, shrublands, and chaparral support a high biodiversity of plants and animals, in addition to high levels of carbon stocks. They provide important air and water quality benefits to all Californians, as well as recreational opportunities and, for forests, harvested wood products for the state. These landscapes are fire-adapted, and historical tribal management of these lands has fostered ecosystem health and resilience. Over the past century, these lands have been impacted severely by fire exclusion, including

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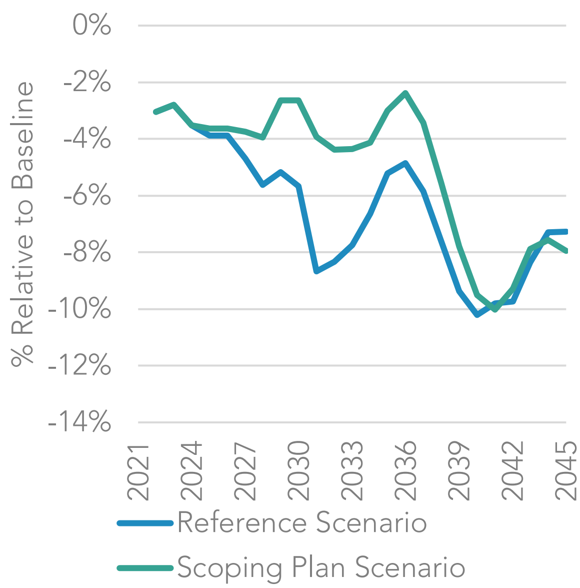
485 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N26, N27. *finalejacrecs.pdf (arb.ca.gov)*.

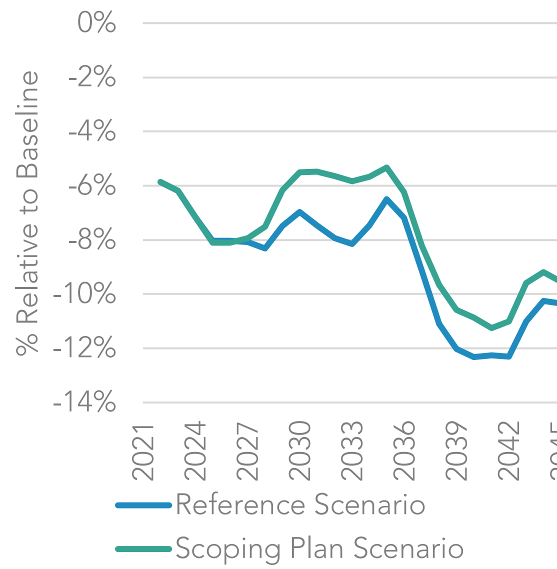
486 CNRA. 2022. *Pathways to 30x30 California*. https://www.californianature.ca.gov/pages/30x30.

exclusion of indigenous people's management and past management practices, which has resulted in less resilient ecosystems and communities and more destructive wildfires today. This, along with drought induced stress and mortality, has changed these landscapes from a carbon sink to a carbon source. Climate smart management can help make forests more resilient to climate change and less prone to catastrophic wildfire. Climate-smart management in shrublands and chaparral face additional challenges and uncertainty, but can still provide protection for threatened communities and natural resources. This management, if conducted on a regular basis to maintain forest health, can help reduce emissions from forests, shrublands, and chaparral, and help strengthen and maintain the co-benefits that Californians experience from them.

Under all management levels, forests and shrublands are expected to lose carbon over the next two decades due to climate change and wildfire (Figure 4-21).

**Figure 4-21: Forest (left) and shrubland (right) carbon stocks by 2045[487,488]**




While this decrease in carbon stocks may be inevitable, forest management under the Scoping Plan Scenario can help direct where and how carbon loss occurs. By proactively managing forests and shrublands, the loss of carbon from wildfire can be lessened as the risk of high severity fire is decreased, with the removed biomass going toward a more

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[487] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N13. finalejacrecs.pdf (arb.ca.gov).

[488] This analysis is the aggregation of all forests and shrublands from all ownerships across the entire state of California.

useful purpose such as harvested wood products, bioenergy, and engineered carbon removal. Managing for a diverse and resilient forest landscape also can help forests recover more quickly so that when climate change and wildfire impacts occur, forests will be less affected and can continue to thrive and sequester carbon. Additional details on the climate benefit potential of forests and shrublands/chapparal can be found in Section 2 of the NWL Climate Smart Strategy.

**Strategies for Achieving Success**

- Accelerate the pace and scale of climate smart forest management to at least 2.3 million acres annually by 2025, in line with the climate smart management strategies identified in this Scoping Plan, the NWL Climate Smart Strategy, and the Wildfire and Forest Resilience Action Plan.[489]
- Establish and expand mechanisms that ensure forests, shrublands, and grasslands are protected from land conversion and that support ongoing, rather than one-time, management actions.
- In collaboration with state and local agencies, accelerate the deployment of long-term carbon storage from waste woody biomass residues resulting from climate smart management, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Expand infrastructure to facilitate processing of biomass resulting from climate smart management.
- Expand permit streamlining in collaboration with state and local agencies to accelerate implementation of climate smart forest management while protecting natural resources.

## Grasslands

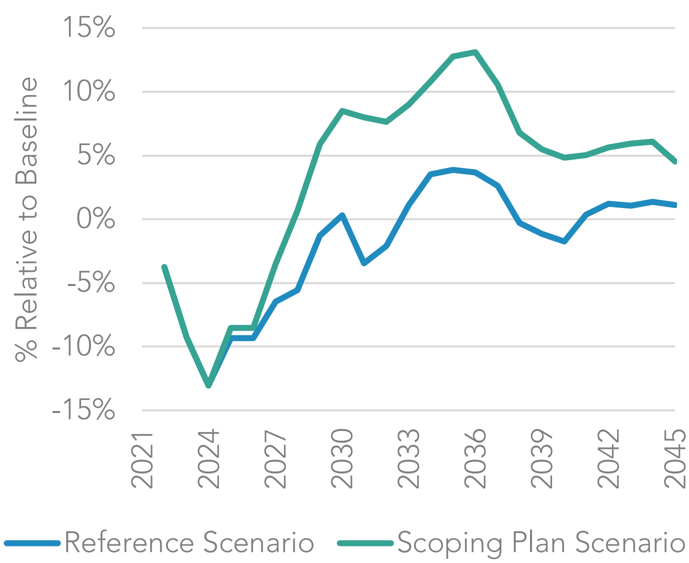
Grasslands cover 9 percent of California, roughly 10 million acres, and are found throughout the state in various landscapes, with concentrations in the foothills surrounding the Sacramento and San Joaquin Valleys. In addition to carbon storage (primarily in the soil), grasslands provide open space, wild habitat, grazing land, and important water filtration and recharge benefits. The protection of grasslands provides an opportunity to reduce sprawl and complement VMT reduction strategies. As grasslands are susceptible to invasive species, climate smart strategies can increase grassland

[489] Forest Management Task Force. 2021. *California's Wildfire and Forest Resilience Action Plan: Recommendations of the Governor's Forest Management Task Force.* https://www.fire.ca.gov/media/ps4p2vck/californiawildfireandforestresilienceactionplan.pdf.

resilience to climate change by improving species diversity and maintaining or increasing soil carbon stocks.

Modeling results show that increased fuels treatments and avoided land conversion can increase carbon stocks on grasslands by 2045, but sequestration rates fluctuate annually. Grasslands are capable of high carbon sequestration rates but are susceptible to carbon losses from wildfire and land conversion. Soil carbon is the major carbon pool on these lands, and continued future improvement of the monitoring and modeling of soil carbon is needed. Similar to forests and shrubland/chaparral, modeling alternatives that include fuels treatments resulted in greater carbon stocks compared to no management, and had lower wildfire emissions. Unlike forests and shrubland/chaparral, which have a general declining carbon stocks trend, the modeling results (Figure 4-22) show grasslands can maintain or increase carbon stocks with active management. Details on the climate benefit potential of grasslands can be found in Section 2 of the NWL Climate Smart Strategy.

**Figure 4-22: Grassland carbon stocks by 2045**




**Strategies for Achieving Success**

- Establish and expand mechanisms that ensure grasslands are protected from land conversion/parcelization and that support ongoing, rather than one-time, management actions that improve carbon sequestration.
- Deploy grassland management strategies, like prescribed grazing, compost application, and other regenerative practices, to support soil carbon sequestration, biodiversity, and other ecological improvements.

- Increase adoption of compost production on farms and application of compost in appropriate grassland settings for improved vegetation and carbon storage, and to deliver waste diversion goals through nature-based solutions.

## Croplands

Croplands cover 9 percent of the state, roughly 9.5 million acres. This land is some of the most productive agricultural land in the world, and enables California to be a global leader in agriculture. Aside from developed lands, croplands are the most intensively managed landscapes in the state, and are closely tied to society through the food they produce and the constant, direct contact that people have with croplands through the course of management. In addition to food security, croplands provide considerable carbon storage in the soil and, in perennial croplands, in aboveground biomass. Climate smart practices can improve public health; for example, by reducing synthetic fertilizer and pesticide use. They also help to maintain or increase the climate resilience of cropland productivity through improved soil conditions and increased pollinator habitat.

There is also significant potential to transform this sector to increase soil carbon storage, reduce GHG emissions (Figure 4-23), and reduce pesticide exposure and health impacts. Moving to an agricultural system that improves soil health and water holding capacity reduces over-application of nitrogen, reduces the use of pesticides and fumigants, and increases biodiversity and pollinator habitat, supporting California's pathway to carbon neutrality while simultaneously improving the lives of those who live and work in the agricultural community. Croplands are intricately tied to people, communities, and their health, and through climate smart practices and cropland conservation, these lands have the potential to contribute more to society than just food.[490] The implementation of climate smart agricultural practices and diversified organic agriculture can help California achieve social and environmental benefits, like improving water use efficiency, increasing pollinator habitat, and reducing synthetic fertilizer and pesticide use.[491] Additional details on the climate benefit potential of croplands can be found in Section 2 of the NWL Climate Smart Strategy.

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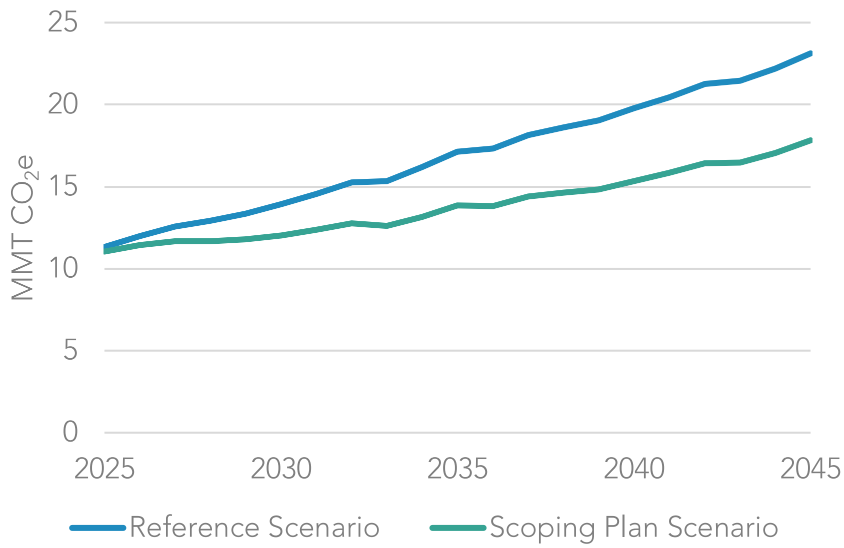
[490] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations In-part (N3, N4, N22), N5, N21. finalejacrecs.pdf (arb.ca.gov).
[491] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. finalejacrecs.pdf (arb.ca.gov).

**Figure 4-23: Cumulative $CO_2e$ emissions from annual croplands in 2045**[492]




CARB recognizes the complex nature of croplands, cross-sector relationships, and the need to build on this analysis to further our understanding of cropland dynamics. Many more aspects of cropland management need to be explored for potential climate benefits, such as water and nutrient use management, pest control methods, crop rotations, and other management practices. The impacts of climate change on water availability, annual/perennial crop growth, and future carbon sequestration trends are uncertain, and recent policies such as the Sustainable Groundwater Management Act may also influence cropland management in unforeseen ways. Nonetheless, it is clear that greater climate smart practice implementation can prepare California for the future and yield tangible benefits for the state.

**Strategies for Achieving Success**

- Accelerate the pace and scale of healthy soils practices to 80,000 acres annually by 2025, conserve at least 8,000 acres of annual crops annually, and increase organic agriculture to 20 percent of all cultivated acres by 2045.

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[492] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. *finalejacrecs.pdf (arb.ca.gov)*.

- Utilize the recommendations included in CDFA's Farmer and Rancher-Led Climate Change Solutions[493] report to accelerate deployment of healthy soils practices, organic farming, and climate smart agriculture practices.
- Establish or expand financial mechanisms that support ongoing deployment of healthy soils practices and organic agriculture.[494]
- Support strategies that achieve co-benefits of safer, more sustainable pest management practices and the health and preservation of ecosystems, such as implementing the California Department of Pesticide Regulation's (DPR's) Sustainable Pest Management Work Group recommendations.[495]
- Conduct research on the intersection of pesticides, soil health, GHGs, and pest resiliency via a multi-agency effort with DPR, CDFA, and CARB.[496]
- Conduct outreach and education to develop and facilitate the increased adoption of safer, more sustainable pest management practices and tools; reduce the use of harmful pesticides; promote healthy soils; improve water and air quality; and reduce public health impacts.
- In collaboration with state and local agencies, accelerate the deployment of alternatives to agricultural burning that increase long-term carbon storage from waste agricultural biomass, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Work across state agencies to reduce regulatory and permitting barriers around some healthy soils practices (e.g., composting), where appropriate.
- Utilize innovative agriculture energy use and carbon monitoring and planning tools to reduce on-farm GHG emissions from energy and fertilizer application or to increase carbon storage, as well as to promote on-farm energy production opportunities.

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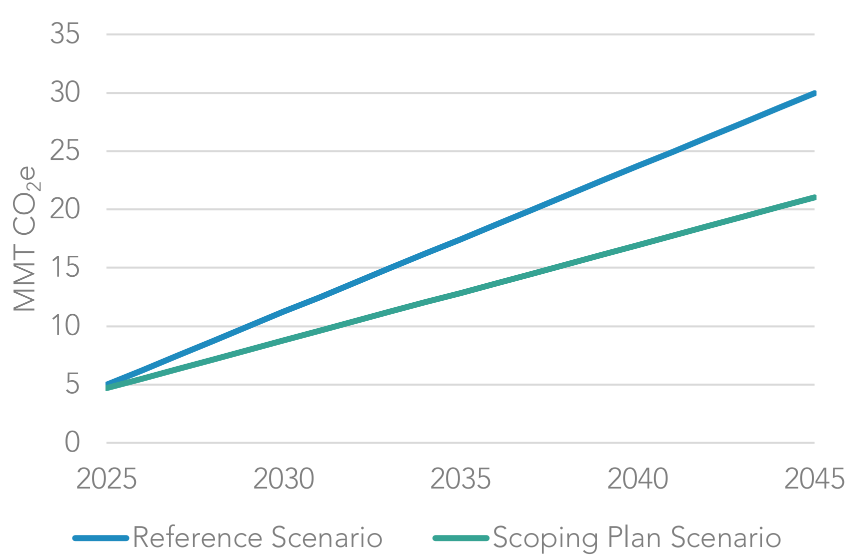
[493] California Department of Food and Agriculture. 2021. Farmer and Rancher Led Climate Change Solutions. https://www.cdfa.ca.gov/oefi/climate/docs/cdfa_farmer_and_rancher-led_climate_solutions_meetings_summary.pdf.
[494] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N7. finalejacrecs.pdf (arb.ca.gov).
[495] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations N3, N4, N5, N7, N22. finalejacrecs.pdf (arb.ca.gov).
[496] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. finalejacrecs.pdf (arb.ca.gov).

## Wetlands

Wetlands cover 2 percent of the state (roughly 1.7 million acres) and include inland and coastal wetlands, such as vernal pools, peatlands, mountain meadows, salt marshes, and mudflats. These lands are essential to California's communities as they serve as hotspots for biodiversity, contain considerable carbon in the soil, are critical to the state's water supply, and protect upland areas from flooding due to sea level rise and storms. Wetlands have been severely degraded through reclamation, diking, draining, and dredging practices in the past, resulting in the emissions of the carbon stored in the soils and the loss of ecosystem benefits. Climate smart strategies to restore and protect all the types of wetlands can reduce emissions while simultaneously improving the climate resilience of surrounding areas and improving the water quality and yield for the state. Restored wetlands also can reduce pressure on California's aging water infrastructure. These benefits beyond emissions reductions will help in the future, as climate change is predicted to negatively affect water supply.

Avoided conversion and restoration of Delta wetlands reduces $CO_2$ and methane emissions from wetlands, with GHG reductions scaling with implementation rates (Figure 4-24). Expansion of conservation and restoration efforts will generate benefits such as the conservation of biodiversity, improved water quality and supply, and reduced flood risk. Additional details on the climate benefit potential of wetlands can be found in Section 2 of the NWL Climate Smart Strategy.

**Figure 4-24: Cumulative $CO_2e$ emissions from Delta wetlands by 2045**




### Strategies for Achieving Success

- Restore 60,000 acres of Delta wetlands annually by 2045 to reduce methane emissions from wetlands and reverse the resulting subsidence.

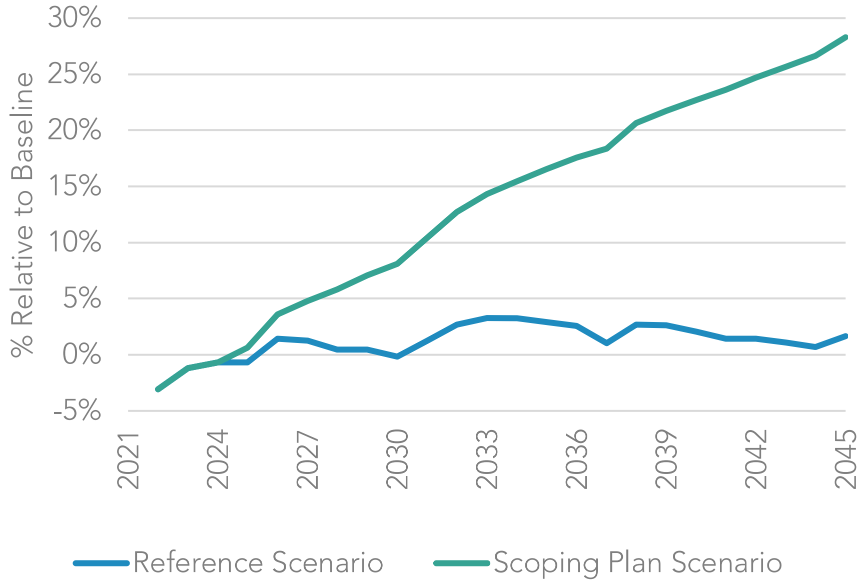
- Identify and prioritize wetland restoration efforts around climate vulnerable communities.
- Leverage other funding and institutions to support wetland restoration projects, including land trusts, local funding (e.g., San Francisco Measure AA), federal funding, and private and philanthropic funding to support wetlands restoration projects.
- Work across state agencies to reduce regulatory and permitting barriers around wetland restoration projects, where appropriate.

## Developed Lands

Developed lands cover 6 percent of the state (roughly 6.8 million acres) and include urban, suburban, and rural areas, as well as transportation and supporting infrastructure throughout California. This area encapsulates the land on which the vast majority of Californians reside and call home. The vegetation within cities and communities, and along infrastructure, are all part of developed lands. This vegetation provides numerous benefits to surrounding areas, including carbon storage, air and water filtration, reduced urban heat island effect, and access to nature, aesthetics, and mental health, among others. These areas are susceptible to climate change as well, and climate smart strategies to protect and expand the urban forests, landscaping, green spaces, parks, and associated vegetation can increase their climate resilience and the benefits Californians derive from them. These strategies also have a significant opportunity to benefit disadvantaged communities, who may not have equitable access to these practices or the benefits they provide. Additional details on the climate and equity benefit potential of developed lands can be found in Section 2 and the Introduction of the NWL Climate Smart Strategy.

Urban forests have a significant potential to sequester carbon (Figure 4-25). They are vastly different from wildland forests, as they require investments to maintain and irrigate. This results in the need for a significant increase in investment to increase urban forest carbon. As urban forests become denser and management difficulty increases, the carbon stock returns on investment diminish, making it expensive to maximize carbon in urban forests. Water availability and irrigation efficiency are also an important consideration for increasing urban forest cover. As water becomes scarcer, the prioritization of irrigating trees over lawns or gardens may be required to achieve increases in urban forest carbon.

**Figure 4-25: Carbon stocks in urban forests by 2045**




Within wildland-urban interface (WUI) areas, defensible space can protect urban and rural communities from wildfire. Analysis results show that 48 percent of parcels are currently fully compliant with defensible space requirements. This highlights how much work needs to be done to protect communities and homes. Defensible space results in a decrease in carbon stocks, as expected when reducing fuels for wildfire.

**Strategies for Achieving Success**

- Increase urban forestry investment annually by 200 percent, relative to business as usual.
- Increase public awareness of urban forest benefits and, where appropriate, prioritizing irrigation of trees over lawns.
- Provide technical assistance and resources to disadvantaged communities to implement community urban greening projects to provide equitable access to the benefits of urban greening projects.[497]
- Work with state and local agencies to expand technical assistance for and enforcement of the defensible space requirements of PRC 4291 to reduce wildfire risk to homes and structures.

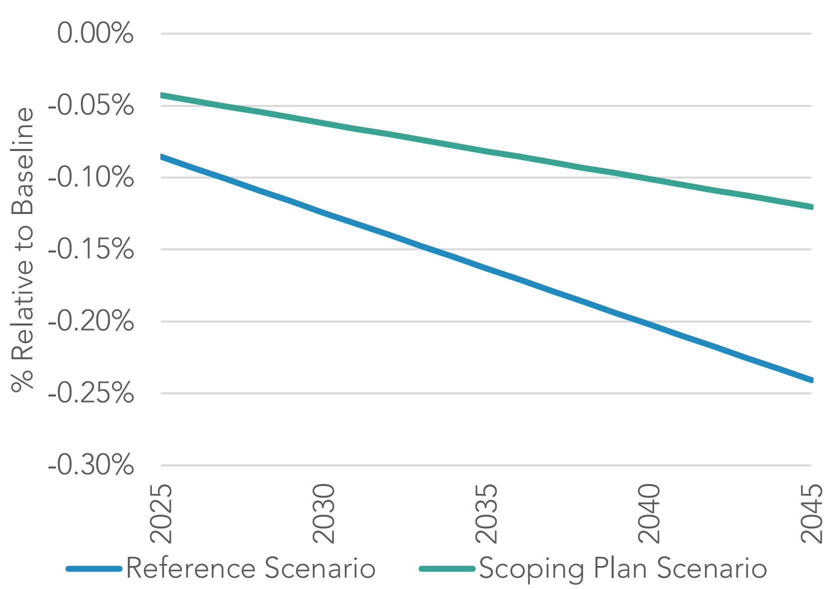
[497] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. *finalejacrecs.pdf (arb.ca.gov)*.

## Sparsely Vegetated Lands

Sparsely vegetated lands cover 10 percent of the state, roughly 10.2 million acres, primarily in the east and southern parts of California. These lands include deserts, beaches, dunes, bare rock, and areas covered in ice and snow (e.g., higher mountain elevations). The limited carbon storage of these lands varies from bare rock and mineral soil to more vegetated areas, though severe climate limits the amount of biomass. Nonetheless, sparsely vegetated lands are important for open space and provide rare and unique habitats for endemic species and a diversity of wildlife. These lands present important recreational opportunities for Californians and serve as important protective buffers in coastal and low-lying areas. Land use change threatens these lands, and conservation efforts are important for protecting these unique areas of California.[498]

Avoided conversion of sparsely vegetated lands reduces the organic carbon lost from the soil, which is the major carbon pool in this land type (Figure 4-26). In identifying the outcomes for sparsely vegetated lands, CARB modeled avoided land conversion to another land use.

**Figure 4-26: Carbon stocks in sparsely vegetated lands by 2045**




### Strategies for Achieving Success

- Establish and expand mechanisms that ensure sparsely vegetated lands are

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[498] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26. finalejacrecs.pdf (arb.ca.gov).

protected from land conversion, prioritizing those areas most vulnerable to climate change and loss.

## Additional Management Strategies

Additional nature-based climate solutions beyond those management strategies modeled for this Scoping Plan are available for implementation, but either cannot currently be modeled and/or affect carbon and the landscape in ways that cannot currently be tracked. Nevertheless, it is important to take action even where these technical gaps exist. Some of these actions, such as cultural burning and indigenous farming practices, have been used on large scales for decades or even centuries, while others are relatively new concepts. The state nevertheless recommends implementing the additional solutions listed here to achieve potential additional climate benefits, as well as other co-benefits. These additional solutions were drawn from the NWL Climate Smart Strategy and stakeholder, tribal government, and interagency feedback.[499]

### Considerations

Although these practices are recommended, because of the lack of in-depth modeling and analysis available, several considerations must be addressed when implementing them. These considerations also apply to the management strategies included in the Scoping Plan Scenario.

- Future climate change impacts are uncertain: The negative impact that climate change can have on the ability of these practices to maintain expected climate benefits is uncertain and may significantly change in the future. Climate change is expected to further diminish the already constricting growing conditions in California, with increasing droughts, more extreme weather events, and expanding disturbances from fire, insects, and disease. It is estimated that suitable habitat for many native plant and animal species could shift, creating novel ecosystems without historical precedent. Close monitoring of all practices, including no management, across our NWL will be critical to understand if and how future climate change affects outcomes and how to adapt management to meet the needs of the system under climate change.[500]

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[499] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N24. [finalejacrecs.pdf (arb.ca.gov)](finalejacrecs.pdf (arb.ca.gov)).

[500] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N15. [finalejacrecs.pdf (arb.ca.gov)](finalejacrecs.pdf (arb.ca.gov)).

- Local conditions: Not every practice is applicable, feasible, or even desirable in every location across California. Implementation of these practices should account for local conditions and needs that may affect the appropriateness of that practice.
- Long-term carbon storage: The ability to sequester additional carbon into NWL is only beneficial to the climate if that carbon stays out of the atmosphere. Many of the additional practices listed here may require continual incentives or interventions to ensure permanence of carbon storage in the soil and biomass. For example, in croplands, it is difficult to estimate how much of the carbon stored by no-tillage can be released by a single subsequent tillage, but a return to conventional tillage would usually be expected to erase most gains.[501,502]
- Scaling actions: There are uncertainties on how these practices may impact both the environment and communities when significantly expanded. For this reason, it is best to take a cautious and measured approach to ramping up actions to a larger scale.
- Infrastructure and operational needs: Scaling up the implementation of some of these practices demands transformational change in the supporting infrastructure and operational frameworks. For example, increasing forest management to the degree included in the Scoping Plan Scenario will require significant changes to wood-processing infrastructure, workforce capacity, permitting processes, technical assistance, and other operational constraints. The increased application of compost to croplands, and potentially to rangelands, will require a significant increase in organic waste and dairy manure collection to increase compost supply, in line with SB 1383. This will also require additional compost production facilities as well as compost/organic waste transportation and application methods.
- Co-benefits: Many co-benefits from these practices exist beyond the climate benefits. These co-benefits include improved public and worker health; improved microbial, insect, and wildlife habitat; enhanced biodiversity; greater labor demand in the nature-based economy; and improved climate resilience.
- Labor and Economics: Many of these practices require additional labor, and an evaluation of how many more jobs are needed to carry out many of these practices

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501 Muñoz-Romero, V., R. J. Lopez-Bellido, P. Fernandez-Garcia, R. Redondo, S. Murillo, and L. Lopez-Bellido. 2017. "Effects of tillage, crop rotation and N application rate on labile and recalcitrant soil carbon in a Mediterranean Vertisol." *Soil Tillage Res.* 169, 118–123.
502 Mitchell, J. P., A. Shrestha, W. R. Horwath, R. J. Southard, N. Madden, J. Veenstra, and D. S. Munk. 2015. "Tillage and cover cropping affect crop yields and soil carbon in the San Joaquin Valley." *California. Agron. J.* 107, 588–596.

is currently unknown. There will also be the need to explore the costs and economic benefits of implementing these additional practices.

- Retreatments: All of these practices have limits on how long they can enhance carbon sequestration. Many of these practices need to be periodically repeated, followed by complementary practices, or maintained through time. This increases costs and requires diligence and long-term stewardship.

## Additional NWL Actions and Strategies

Below is a set of additional actions that should be taken on California's natural and working lands. Again, these practices were not modeled for this Scoping Plan, and all of the considerations listed above should be taken into account before implementing the following actions.

- Conservation of all NWL types (in line with the NWL Climate Smart Strategy and CNRA's Pathways to 30x30 California) is critical to ensuring continued carbon sequestration and provision of co-benefits from these lands for all Californians.[503]
- Reforestation following disturbance, using appropriate species, is an impactful practice that can help prevent conversion away from forestland and establish new trees to sequester carbon. The number of acres that may need reforestation following high severity wildfires is estimated to continue to increase into the future.
- Restoration of shrublands, chaparral, riparian zones, and oak woodlands across California includes a variety of practices to alter their structure and return endemic species to the areas. These unique habitats provide multiple co-benefits to the state, such as clean water, reduced wildfire risk, and biodiverse habitats for flora and fauna.
- Conservation and restoration of wetlands, beyond the Delta wetlands included in the NWL modeling, can protect these unique habitats and the climate benefits they provide. These wetland types can include but are not limited to coastal wetlands, mountain meadows, vernal pool complexes, alkali sinks and meadows, and floodplains.
- Conservation and restoration of seagrasses and seaweeds provide a number of benefits, including carbon storage and sequestration, habitat provision for many culturally and commercially important species of fishes and invertebrates, shoreline protection, and tourism opportunities.[504]

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[503] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26, N27. *finalejacrecs.pdf (arb.ca.gov)*.

[504] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. *finalejacrecs.pdf (arb.ca.gov)*.

- Prescribed herbivory utilizes various livestock to consume vegetation to reduce fuel loads across an area. This fuel management practice can be used in forests, grasslands, and shrublands as an effective alternative to herbicide use, and should be considered wherever local conditions allow.
- Urban and community greening efforts such as green schoolyards, urban farms, rain gardens, community gardens, community composting, and many more provide numerous health benefits to communities.
- Additional Healthy Soils Program practices on annual croplands such as conservation cover and crop rotation, biomass planting for borders, wind barriers, riparian areas, and improved nutrient management can improve soil health, water retention, and increase carbon stocks.
- Healthy Soils Program practices on perennial croplands and rangelands, such as compost application and alley cropping/cover cropping to improve soil health, water retention, erosion control, and biomass growth.[505]
- Stacking of these Healthy Soils Program practices, where appropriate, in perennial and annual systems, can synergistically improve soil health and provide multiple benefits.
- Mulching adds high carbon materials to croplands or fallowed lands to reduce competing vegetation and retain moisture. This practice can support other benefits such as reduced water use and reduced synthetic pesticide and fertilizer use, as well as provide a use for suitable forest and agricultural waste biomass.
- Reductions in the use of synthetic fertilizers in cropland management, generally supported by the implementation of new management tools or technologies, can lead to reductions in GHG emissions from the production and application of fertilizers. This benefit is in addition to the co-benefits of reduced chemical runoff into waterways and reduced exposure of human populations to their harmful effects.

[505] Various types of organic amendments are being researched for application to particular landscape types. For example, compost application to rangelands is a relatively new practice that has been shown to improve soil health and increase carbon sequestration in the short term, though the science on the long-term impacts of this practice is still developing and the supply of available compost may be limiting.

# Chapter 5: Challenge Accepted

This chapter provides an overview of the next steps and partnerships that will be needed to successfully implement this Scoping Plan. The path forward is not dependent on one agency, one state, or even one country. It will take action on a global level to address the threat climate change poses. But, the work begins at home.[506] The state can lead by engaging Californians and demonstrating how action at the state, regional, and local levels of government, as well as action at community and individual levels, can contribute to addressing the challenge before us. We must build partnerships with academic institutions, private industry, and others to support and accelerate the transition to carbon neutrality. Ultimately, the success of this Scoping Plan will be measured by our ability to implement the actions modeled in the Scoping Plan Scenario at all levels of government and society. This will depend on a mix of legislative action, regulatory program development, incentives, institutional support, workforce and business development, education and outreach, community engagement, and research and development and deployment. Optimizing this mix will help to ensure that clean energy and other climate mitigation strategies are clear, winning alternatives in the marketplace and in communities—to promote equity, drive innovation, and encourage consumer adoption. Bold institutional action will catalyze continued research and push private investment to create jobs and bring innovative ideas to reality.

## State-level Action

Achieving the targets described in this Scoping Plan will require continued commitment to and successful implementation of existing policies and programs and identification of new policy tools and technical solutions to go further, faster. California's Legislature and state agencies will continue to collaborate to achieve the state's climate, clean air, equity, and broader economic and environmental protection goals. It will be necessary to maintain and strengthen this collaborative effort, and to draw upon the assistance of the federal government, regional and local governments, tribes, communities, academic institutions, and the private sector to achieve the state's near-term and longer-term emission reduction goals and a more equitable future for all Californians.

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[506] This "polycentric" approach to climate challenges, engaging many levels of government, was articulated in leading papers by Nobel laureate Elinor Ostrom. See, for example, Ostrom, E. 2014. "A Polycentric Approach to Coping with Climate Change." *Annals of Economics and Finance* 15-1, 97–134.

## Regulations and Programmatic Development

Meeting the AB 32 2020 GHG emissions reduction target several years earlier than mandated demonstrated that developing mitigation strategies through a public process, where all stakeholders have a voice, leads to effective actions that address climate change and yields a series of additional economic and environmental co-benefits to the state. Following adoption of this Scoping Plan, state agencies will continue to update and implement new and existing programs to align with the outcomes in the plan. Community, tribal, and stakeholder engagement will be a critical part of this work. Several state agencies, including CARB, the CEC, the California State Transportation Agency (CalSTA), the CPUC, and others will need to be part of various subsequent rulemaking processes. Each of these agencies' leadership and technical staff will engage with the public through public meetings, written and oral comment, and other methods of engagement. This work will be informed by evaluations of the health, air quality, environmental, equity, and economic benefits and impacts of regulations, including an assessment of the societal cost of carbon, as required under AB 197.

## Incentive Programs

As described in Chapter 1, incentive programs are one of the most important tools the state has in advancing our low carbon future, especially for climate vulnerable communities. The programs ensure clean technology and energy are accessible and are critical to closing ongoing opportunity gaps. These programs also leverage private-sector investment and build sustainable, growing markets for clean and efficient technologies, and they are particularly necessary to support GHG emission reduction strategies for priority sectors, sources, and technologies. Clean technologies are often already the best and lowest cost option over their lifetimes but incentive funding is critical to ensure that they are broadly available, especially in climate vulnerable communities. Incentives also build on California's long track record of driving innovative technology developments, and creating new industries, with targeted investment. The Inflation Reduction Act also provides a new source of funding and tax incentives that must be leveraged to help achieve the state's climate goals.

Many state funding programs are designed to achieve multiple objectives simultaneously: reduce emissions from GHGs, criteria pollutants, and toxic air contaminants; manage natural and working lands for carbon sequestration; and address health and opportunity gaps in disadvantaged communities. California's incentive programs focused on jump-starting the transition to a zero emission transportation future are a good example of this "stacked" approach. The state is investing billions of dollars through programs such as the On-Road Heavy-Duty Voucher Incentive Program and Clean Cars 4 All in order to replace the light- and heavy-duty vehicles most responsible for the state's GHG emissions and poor air quality, all while bolstering the nascent ZEV market. Further strategies aid in developing new technologies, in ramping up access for all, and in shifting to cleaner modes of transport; for instance, by supporting investments in walkable, bikeable communities and transit, as well as in vehicles. This funding strategy is, of course, paired with the regulatory approach described above.

## Local Action

Local action by cities can support and amplify efforts to reduce GHGs. For example, the City of Oakland requires all new construction to be all-electric and is currently working on electrifying existing buildings.[507] In addition, starting in 2023, the City of Sacramento will require all new buildings under three stories to be all-electric, and it extends the mandate to all new construction by 2026 with some limited exemptions. The City of Sacramento also requires levels of EV charging infrastructure in new construction starting in 2023, higher than the minimum state requirements, and provides parking incentives for zero-emission carsharing and EV charging.[508] Local governments asserting this type of leadership are critical partners in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment.

California must accommodate population and economic growth in a far more sustainable and equitable manner than in the past. Good climate policy can and should create affordable and pleasant places to live, with effective transport and clean air for all—a future in which local governments and communities are central partners. Local governments have the primary authority to plan, zone, approve, and permit how and where land is developed to accommodate population growth, economic growth, and the changing needs of their jurisdictions. They also make critical decisions on how and when to deploy transportation infrastructure, and can choose to support transit, walking, bicycling, and neighborhoods that do not force people into cars. Local governments also have the option to adopt building ordinances that exceed statewide building code requirements, and play a critical role in facilitating the rollout of ZEV infrastructure. As a result, local government decisions play a critical role in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment—the two largest GHG emissions sectors over which local governments have authority.

Local governments are also frequently the source of innovative and practical climate solutions that can be replicated in other areas. Their efforts to reduce GHG emissions within their jurisdictions are vital to achieving the state's near-term air quality and long-term climate goals. Local governments must continue to take action that affirmatively

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[507] City of Oakland. Building Electrification. https://www.oaklandca.gov/projects/building-electrification.
[508] City of Sacramento. Electrification of New Construction. http://www.cityofsacramento.org/SacElectrificationOrdinance.

builds the projects and expend the funds needed to further the state's collective path toward equitable emissions reductions. As such, aligning local jurisdiction action with state-level priorities to tackle climate change and the outcomes called for in this Scoping Plan is critical to achieving the statutory targets for 2030 and 2045. Local governments can implement climate strategies that can effectively engage residents by addressing local conditions and issues that also deliver local economic benefits.

## Local Climate Action Planning and Permitting

California encourages local jurisdictions to take ambitious, coordinated climate action at the community scale; action that is consistent with and supportive of the state's climate goals.[509] As discussed in more detail in Appendix D (Local Actions), local jurisdictions can do much to enable statewide priorities, such as taking local action to help the state develop the housing, transport systems, and other tools we all need. Indeed, state tools—such as the Cap-and-Trade Program or zero-emission vehicle programs—do not substitute for these local efforts. Multiple legal tools are open to local jurisdictions to support this approach, including development of a climate action plan (CAP), sustainability plan, or inclusion of a plan for reduction of GHG emissions and climate actions within a jurisdiction's general plan. Any of these can help to align zoning, permitting, and other local tools with climate action.

Once adopted, the GHG emissions reductions plans detailed in CAPs can provide local governments with a valuable tool for coordinated climate planning in their community. When a local CAP complies with CEQA requirements, individual projects that comply with the CAP are allowed to streamline the project-specific GHG analysis.[510,511] Effectively, local governments that adopt a CEQA-compliant CAP enable project developers to use this streamlined approach. This saves time and resources and provides more consistent expectations for how GHG reduction measures are applied across projects in the jurisdiction. While the state encourages local governments to follow this approach, we acknowledge not all jurisdictions have the resources to develop a CAP that meets the CEQA requirements.

In addition to being required for a local CAP to comply with CEQA, local GHG reduction targets have long been recommended as part of the process of developing a climate

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[509] This plan provides more detailed guidance and tools to local governments in Appendix D (Local Actions).

[510] Cal. Code of Regs., tit. 14, § 15183.5.

[511] California Governor's Office of Planning and Research. n.d. "General Plan Guidelines - Chapter 8 Climate Change."

action plan.[512] One challenge local jurisdictions have faced is how to evaluate and adopt quantitative, locally appropriate goals that align with statewide goals. An effective response to this challenge is to focus on goals that can help implement overall state priorities—enabling the key transformations California needs.

There are many ways that local governments can make key contributions to this transformation, depending on the characteristics of their jurisdiction and community. For example, some jurisdictions will inherently have more land capacity to remove and store carbon, whether through natural and working lands or by other means. Other jurisdictions will be host to GHG-emitting facilities that serve necessary functions and will take time to transition to clean technology (e.g., municipal wastewater treatment plants, landfills, and energy generation and transmission facilities). It is important to recognize that we will need to build new energy production and distribution infrastructure, and repurpose existing ones, for clean technology and energy before we are able to phase down existing fossil sources. There also will be a need to handle the significant amount of biomass resulting from sustainable forest management for catastrophic wildfire prevention, agricultural waste, and landfill diversion.

Regional efforts can support change too: energy and transportation systems that serve Californians do not stop at jurisdictional boundaries, and some local decisions can have ramifications for other communities. For instance, Metropolitan Planning Organizations (MPOs) can help to integrate local efforts by planning consistent with the Scoping Plan and Climate Action Plan for Transportation Infrastructure, including by removing polluting roadway capacity expansions from project pipelines and instead focusing on climate-friendly solutions. These varied capabilities and needs should be taken into account in setting targets for local climate plans. For instance, although net zero targets can often be valuable and achievable, and mitigation is important, targets should be considered in the larger context of these goals. This all means any GHG targets on a local scale should take into consideration the actions and outcomes included in this Scoping Plan. Jurisdictions considering "net zero" targets should carefully consider the implications such targets may have on emissions in neighboring communities and the ability of the state to meet our collective targets.

Jurisdictions without formal CAPs also have important opportunities within this context. These jurisdictions can still take actions that effectively translate key state plans, goals, and targets, including those articulated in this Scoping Plan for local action. For instance, state ZEV targets can advance local efforts to promote broad and equitable access to charging and fueling. Similarly, local jurisdictions can enable reduced dependence on

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[512] Climate Smart Communities. 2014. Climate Action Planning Guide. https://cdrpc.org/wp-content/uploads/2015/05/CAP-Guide_MAR-2014_FINAL.pdf.

single-occupancy vehicles by supporting dense infill housing and transit, among other actions. Such actions can be reflected in particular project plans, in general plans, or through other local policies. Regional partnerships among these jurisdictions can also help tap resources and provide for more effective overall action.

## Unlocking CEQA Mitigation for Local Success

The California Environmental Quality Act also provides important tools for lead agencies to support the achievement of the state's GHG and VMT reduction goals. Although many climate-friendly local government actions already fall into categories that may not require a full CEQA analysis, thanks to streamlining or other tools, and although certain product types (such as affordable infill housing) are generally clearly consistent with state climate goals, CEQA analyses may still sometimes be required. CEQA can be a powerful and useful tool to engage the public, identify additional opportunities to support climate efforts, and localize change. It is important that lead agencies look for ways to use CEQA to support these core purposes, ensuring that these processes do not become sources of delay but instead unlock more opportunities. The uncertainty analysis in Chapter 2 evaluates how project implementation delays can lead to missed state climate targets and continued dependence on fossil energy. Mitigation measures applied in the communities affected by projects subject to CEQA have the added benefit of improving health, social, and economic resiliency as climate impacts worsen.

Appendix D (Local Actions) explores the role of local government action and CEQA in detail. As discussed there, an important CEQA-related tool is mitigation—which can be used to further drive local action consistent with state climate goals. When a lead agency determines that a proposed project would result in potentially significant GHG impacts due to its GHG emissions or a conflict with state climate goals, the lead agency must impose feasible mitigation measures to minimize the impact. Appendix D (Local Actions) provides suggestions for prioritizing the various types of mitigation, starting with on-site GHG-reducing design features[513] and mitigation measures, such as methods to reduce VMT and support building decarbonization, access to shared mobility services or transit, and EV charging. After exhausting all the on-site GHG mitigation measures, CARB recommends prioritizing local, off-site GHG mitigation measures, including both direct investment and voluntary GHG reduction or sequestration projects, in the neighborhoods impacted by the project. This could include, for example, development of a neighborhood green space, investment in street trees, or expansion of transit services. Implementing GHG mitigation measures in the project's vicinity would allow the project proponent and the lead agency to work directly with the affected community to identify and prioritize the

[513] Cal. Code of Regs., tit. 14, § 15126.4(c)(2) and (3).

mitigation measures that meet their needs while minimizing multiple environmental and societal impacts.

Once all potential on-site and local off-site GHG mitigation measures have been incorporated to the extent feasible, Appendix D (Local Actions) provides further suggestions for prioritizing other mitigation types, including non-local off-site mitigation, and voluntary offsets issued by a recognized and reputable voluntary carbon registry (as listed on CARB's website[514]) may be appropriate. Additional in-state mitigation also may be available in the upcoming SB 27[515] (Skinner, Chapter 237, Statues of 2021) registry, which will serve as a database of projects in the state that drive climate action on natural and working lands. Lead agencies should use substantial evidence to demonstrate that the project proponent explored and prioritized investments in feasible, local mitigation prior to moving mitigation to a geography located farther away from the project.

## Communities and Environmental Justice

As noted in Board Resolution 20-33,[516] it is incumbent on CARB to function as an agent of responsible social change, especially when it is clear that environmental injustices continue to persist for low-income communities, tribes, and communities of color.

State law defines *environmental justice* as the fair treatment of all people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.[517] Government Alliance for Race and Equity (GARE)[518] defines *racial equity* as when race can no longer be used to predict life outcomes and outcomes for all groups are improved.

For this Scoping Plan to be successful, it must address environmental justice and advance racial equity. Implementation of the plan needs to address the needs of those communities that are disproportionately burdened by climate impacts and continue to face significant health and opportunity gaps. Now, we need to ensure our actions allow these communities to not only have a seat at the table, but also inform and shape the policies

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[514] CARB. 2022. Offset Project Registries. https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/offset-project-registries.

[515] SB 27. Carbon sequestration: state goals: natural and working lands: registry of projects. (SB 27, Skinner, Chapter 237, Statutes of 2021). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB27.

[516] CARB. 2020. Resolution 20-33: A Commitment to Racial Equity and Social Justice. October 22. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2020/res20-33.pdf.

[517] Gov. Code, § 65040.12, subd. (e).

[518] Local and Regional Government Alliance on Race and Equity. 2015. *Advancing Racial Equity and Transforming Government: A Resource Guide to Put Ideas into Action.* Page 9. https://racialequityalliance.org/wp-content/uploads/2015/02/GARE-Resource_Guide.pdf.

to ensure their communities thrive. With this Scoping Plan, the state also adds a new tool to identify which communities will be the least resilient in the face of selected climate impacts and will see disproportionate economic impacts as a result. As described in Chapter 3, the CVM will enable the state to target programs and policies to build resiliency in the specific regions that will feel climate impacts more acutely due to existing health and opportunity disparities leading to disproportionate economic impacts. This tool will be critical in the state's efforts to address climate impacts while accounting for environmental injustices and racial inequities. CARB will incorporate the CVM into its work as it moves forward and will share this new tool with other agencies to align our efforts. The goal is to keep expanding the CVM to incorporate additional climate impacts to better identify disproportionate economic impacts as community level data becomes available.

AB 617 is another important tool for both Air Districts and CARB to bring resources to communities that have long been disproportionately burdened by poor air quality. While AB 617 does not require local agencies to participate in the Community Air Protection Program, several AB 617 communities are finding ways to bring local land use agencies to the table to respond to community priorities. We look forward to more opportunities to foster relationships with local authorities and continued collaboration between state and air district programs.

In alignment with AB 32, and to ensure environmental justice and racial equity were integrated into this Scoping Plan, CARB reconvened the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB on the development of this Scoping Plan. Since reconvening in May 2021, the EJ Advisory Committee has engaged in the following activities:

- In October 2021, the EJ Advisory Committee sent a letter to the governor requesting a timeline extension for the Scoping Plan process. In response to the EJ Advisory Committee's letter, CARB modified this Scoping Plan process[519] and committed to an active engagement with the EJ Advisory Committee following the approval of this Scoping Plan. The EJ Advisory Committee also presented to the CARB Board[520] at its October 2021 Board meeting, reiterating its request for a timeline extension, as well as sharing additional concerns about process.

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[519] Randolph, L. M. 2021. LMR October 19 response to Environmental Justice Advisory Committee Letter. https://ww2.arb.ca.gov/sites/default/files/2021-10/LMR%20October%2019%20response%20to%20EJAC%20Letter%20Final.pdf.

[520] Argüello, M. D., K. Hamilton, S. Taylor, and P. Torres. 2021. EJ Advisory Committee Co-Chair Informational Presentation to CARB Board. October 28. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2021/102821/21-11-4pres.pdf.

- In December 2021, the EJ Advisory Committee shared its responses to Scenario Input Questions,[521] as well as a narrative document outlining their concerns[522] around the process, the need for evaluation, and the need for a tribal representative. In response to the EJ Advisory Committee Scenario Input Questions, CARB incorporated the EJ Advisory Committee responses into the Scenario Assumptions document,[523] and modeled results from PATHWAYS.[524] In response to the EJ Advisory Committee's concerns, CARB worked diligently to appoint a tribal representative[525] in February 2022, and to outline additional opportunities for the EJ Advisory Committee to engage in the Scoping Plan process.[526]
- In March 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[527] and walked through their preliminary draft recommendations to inform this Scoping Plan. In April, the EJ Advisory Committee shared its revised preliminary draft recommendations[528] to inform this Scoping Plan.
- In September 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[529] and engaged in discussion about priority items as they relate to incorporating environmental justice into the Scoping Plan. By the end of September, the EJ Advisory Committee shared its final

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[521] EJ Advisory Committee. 2021. EJ Advisory Committee Final Responses to CARB Scenario Inputs. December 2. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf*.

[522] EJ Advisory Committee. 2021. EJ Advisory Committee Responses to Scenario Input Questions. EJ Advisory Committee narrative document regarding scenario input recommendations. December 1. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Narrative%20Document%20re%20Scenario%20Input%20Recommendations%2012_1_2021.pdf*.

[523] CARB. 2021. PATHWAYS Scenario Modeling. *https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf*.

[524] E3. 2022. CARB Draft Scoping Plan AB32 Source Emissions Initial Modeling Results. March 15. *https://ww2.arb.ca.gov/sites/default/files/2022-03/SP22-Model-Results-E3-ppt.pdf*.

[525] CARB. AB32 EJ Advisory Committee Meeting, February 28, 2022 CARB Update. *https://ww2.arb.ca.gov/sites/default/files/2022-02/CARB%20EJAC022822presentation.pdf*.

[526] Fletcher, C. 2021. CARB Response to EJ Advisory Committee Narrative. CARB. December 15. *https://ww2.arb.ca.gov/sites/default/files/2021-12/CARB%20response%20to%20EJAC%20Narrative.pdf*.

[527] EJ Advisory Committee. 2022. EJ Advisory Committee Presentation: Preliminary Draft Recommendations. March 10. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacpres.pdf*.

[528] AB 32 EJ Advisory Committee. Draft Recommendations. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacrecsrevised.pdf*.

[529] EJ Advisory Committee. 2022. EJAC Presentation. September 1. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/ejacpres.pdf*

recommendations[530] to inform this Scoping Plan. To the extent possible, CARB has incorporated and cited these recommendations through this Scoping Plan.

In addition to the activities listed above, Central Valley EJ Advisory Committee members hosted a successful community engagement workshop[531] in San Joaquin Valley in February 2022 with over 100 attendees. Members of EJ Advisory Committee hosted a statewide community engagement workshop[532] in June 2022 with more than 165 attendees. Throughout the EJ Advisory Committee's process, members of the Committee continued to work with their communities to ground truth their recommendations to inform the development of the Scoping Plan. The EJ Advisory Committee worked hard to ensure the voices of those communities most burdened by climate impacts were reflected in the plan. The EJ Advisory Committee will continue to play an ongoing role in the implementation of this Scoping Plan to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us.

To the extent possible, the EJ Advisory Committee's recommendations were integrated throughout the plan. This plan directly cites instances where there is alignment between the plan and the EJ Advisory Committee recommendations. This approach seeks to ensure there is more transparency and identify consensus that exists, as well as relevant ways equity and environmental justice are addressed in this plan and in the planning for future related implementation activities. CARB is dedicated to its efforts to ensure this plan does not leave communities behind.

As this Scoping Plan moves into the implementation phase, there will be a need to better understand how to address EJ Advisory Committee recommendations on the following topics:

- Actions under the jurisdiction of other agencies: there are certain EJ Advisory Committee recommendations that are outside of CARB's jurisdiction. As the EJ Advisory Committee continues to convene, it would be helpful to understand the

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[530] EJ Advisory Committee. 2022. EJAC 2022 Scoping Plan Recommendations. September 30. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf*

[531] San Joaquin Valley Climate Justice & the Scoping Plan. 2022. *https://ww2.arb.ca.gov/sites/default/files/2022-07/SJV%20Climate%20Justice%20%26%20the%20Scoping%20Plan%20Workshop%20Report%20out%20%26%20Recommendations_5.2022.pdf*

[532] EJAC. 2022. *EJAC/Community Engagement Synthesis Report '22.* *https://ww2.arb.ca.gov/sites/default/files/2022-07/EJAC-CommunityEngagement-SynthesisReport-2022-English%26Spanish.pdf*.

role that CARB can play as it relates to the EJ Advisory Committee's recommendations for actions outside CARB's jurisdiction and coordinates with sister agencies.

- Actions that require legislative direction: there are certain EJ Advisory Committee recommendations that would require legislative action. As the EJ Advisory Committee continues to convene, it will be helpful to understand how CARB can work with the EJ Advisory Committee to share these recommendations with the appropriate members of the Legislature.
- Actions directly tied to implementation activities: This Scoping Plan is not an implementation document; it is a plan to chart a course to continue to reduce GHG emissions and achieve carbon neutrality. Once the Scoping Plan is approved, there will be follow-up action at CARB, as well as at other agencies. In these follow-up efforts, there will be a role for ongoing EJ Advisory Committee engagement.
- Actions to implement recent legislation, such as SB 905.

CARB proposes to continue to work with the EJ Advisory Committee to better understand how to move forward on EJ Advisory Committee recommendations that fall into the topics listed above and any other recommendations that were not included in this plan. It is also important to note that there are numerous recommendations where CARB shares the goals of the EJ Advisory Committee and can assist in implementation steps. Examples include the following:

- CARB shares the goal of prioritizing non-fossil energy generation and supports non-fossil projects and opportunities to locate behind-the-meter clean resources in communities of concern in programs such as the Solar on Multifamily Affordable Housing program.
- CARB will engage with agencies and academic institutions to further workforce development.
- Many other recommendations related to financial support for various energy projects, such as microgrids, are within the purview of the CPUC or local publicly owned utilities. Similarly, utility scale projects are within the jurisdiction of other agencies. However, CARB supports strategies identified in the recommendations such as offshore wind to reduce the reliance on fossil fuel generation.
- CARB is supportive of rooftop solar, although it is not within CARB's jurisdiction to determine how incentives for those projects are structured.
- CARB is supportive of strong energy decarbonization goals, recognizing that increased reliance on electrification in transportation and other sectors will create significant demand for electricity, and therefore ensuring reliability of a decarbonized grid is a critical need for the state.
- In the transportation sector, CARB is supportive of the EJ Advisory Committee's recommendations to maintain aggressive zero emission vehicle goals consistent

with its statutory mandate to ensure regulations are technologically feasible and in alignment with Governor Newsom's ZEV Executive Order (EO N-79-20). CARB looks forward to continued engagement on rulemakings that will implement these goals.

- As noted elsewhere in this plan, CARB is supportive of the Caltrans California Transportation Plan 2050 and the California Climate Action Plan for Transportation Infrastructure.
- CARB is supportive of additional public support for transit. CARB is supportive of locating EV charging in low-income communities and communities of color.
- CARB is supportive of prioritizing funding incentives for transit and heavy- and medium-duty vehicles, although CARB does believe there is an important role for incentives that support adoption of light-duty vehicles for the time being. CARB will also be opening a rulemaking on the Low Carbon Fuel Standard to ensure it continues to support clean fuels that will displace petroleum fuels and will consider the EJ Advisory Committee recommendations on this program.
- In the industrial sector, in addition to the strategies discussed more fully in this Scoping Plan, CARB continues to work with the Legislature, local agencies, and air districts to support, implement, and enforce effective reductions in emissions of GHGs and air pollutants in stationary sources. The air districts have the authority to directly issue permits addressing a facility's criteria pollutant and toxics emissions levels. These levels are set after careful permit review, under district regulation and statute. However, AB 617 directs and authorizes CARB to take several actions to improve data reporting from facilities, air quality monitoring, and pollution reduction planning for communities affected by a high cumulative exposure burden. CARB will continue to implement AB 617 and look for ways to strengthen the Community Air Protection Program.
- Considerations around the phaseout of oil and gas extraction and refining, and the role of carbon capture are discussed more thoroughly in Chapter 2.

As CARB continues to engage with the EJ Advisory Committee—in addition to the EJ Advisory recommendations that have been integrated throughout this plan—below are the following commitments that CARB is making to ensure that environmental justice is integrated in this plan and its implementation:

- Building decarbonization is a pillar of this Scoping Plan and CARB commits to working closely with state and local agencies to implement the EJ Advisory Committee recommendations that call for prioritization for residents in low-income communities and communities of color in this transition.
- CARB commits to sharing the EJ Advisory Committee's recommendations with the CEC, CPUC, and other agencies administering funds to support building

decarbonization, and to work closely with those agencies as they engage in public processes to further building decarbonization.

- CARB has committed to review the Cap-and-Trade program and determine what potential legislative or regulatory amendments could be necessary to ensure the program continues to deliver GHG reductions needed to achieve the statutory climate goals. In that process, CARB will consider the recommendations of the EJ Advisory Committee[533] and Independent Emissions Market Advisory Committee,[534] as well as others.

Critically, the EJ Advisory Committee makes numerous recommendations centered around tracking progress of the various strategies in this Scoping Plan. Currently, progress is tracked and reported in numerous ways, including the annual GHG inventory and reports to the Legislature. Part of the ongoing work of implementation, however, will include consideration of ways to provide more data and information to the public, such as rates of deployment of clean energy and technology as described in Chapter 1. CARB will also continue to collaborate with CDPH and OEHHA on health metrics to track cumulative benefits of air pollution and climate programs, especially in low-income communities and communities of color.

As noted earlier in this document, the EJ Advisory Committee will continue to play a vital role in the Scoping Plan and its implementation to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us. This includes ongoing EJ Advisory Committee engagement to advise CARB on the development of the Scoping Plan and any other pertinent matters in implementing AB 32. The ongoing EJ Advisory Committee will help to ensure integration of environmental justice in implementation efforts as it relates to AB 32, and also help CARB as we work toward a future where race is no longer a predictor for life outcomes.

## Academic Institutions and the Private Sector

Academic institutions produce and present the latest science on both the impacts of, and actions to reduce, climate change damages. They are also leading the way by

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[533] California Legislative Information. Bill Text – AB 32. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[534] California Legislative Information. Bill Text – AB 398. California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. (AB 398). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

establishing their own climate goals and GHG emissions reductions targets.[535, 536, 537] They are incubators for innovation and knowledge in clean energy and technology and play an important role in adding to the wealth of robust information to inform policies and programs. Academic institutions have the ability to fill knowledge gaps and push us toward new frontiers. As we move forward, we will continue to see these institutions as partners and resources that can help CARB look for ways to accelerate and introduce actions to reduce GHG emissions and remove and store carbon.

As such, it will be important to maintain and enhance relationships with academic institutions, including community colleges. Community colleges are more likely to have a large proportion of first generation students or students that come from low-income communities or communities of color. The perspective of this diverse student body will be critical to inform discussions on climate change damages and mitigation efforts. This student body is also a future workforce, and courses to teach the skills for a sustainable economy are a chance to close historical opportunity gaps. Importantly, many of the students at community colleges are local residents and community members. This engagement provides another way to invest in communities across our state. The Foundation for California Community Colleges is already leading the way through innovate programs such as their Good Jobs Challenge - California Resilient Careers in Forestry.[538] These types of programs could be replicated across other sectors. CARB will evaluate how to leverage the requirements in AB 680 on workforce development in the California Climate Investments programs with the work at the Foundation for California Community Colleges.

As noted in Chapter 1, public and private partnerships will be important as we move forward in the great energy transition. But the private sector is also important in the context of research and development and deployment. Many of these companies have the resources and expertise to build and produce the clean technology and energy we will need. It was through the efforts of several private companies (Bell, Exxon, Telecom

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[535] University of California. Our Commitment. *https://www.universityofcalifornia.edu/initiative/carbon-neutrality-initiative/our-commitment*.
[536] California State University. Energy, Sustainability, & Transportation. *https://www.calstate.edu/csu-system/doing-business-with-the-csu/capital-planning-design-construction/operations-center/Pages/energy-sustainability.aspx*.
[537] California Community Colleges Chancellor's Office. Climate Action and Sustainability. *https://www.cccco.edu/About-Us/Chancellors-Office/Divisions/College-Finance-and-Facilities-Planning/Facilities-Planning/Climate-Action-and-Sustainability?msclkid=4a72350ec4f511ecaf292c6b14ac9a4f*.
[538] Foundation for California Community Colleges. 2022. Good Jobs Challenge. Developing Resilient Careers in Forestry for Californians. *https://foundationccc.org/What-We-Do/Workforce-Development/Good-Jobs-Challenge*.

Australia) that the photovoltaic solar panels in use today were developed.[539] Similarly, it was companies such as General Electric and Texas Instruments that contributed to the development of hydrogen fuel cells.[540] This Scoping Plan includes the known and emerging clean technologies and fuels available today. The private sector spirit of invention, improvement, and innovation must continue to deliver new tools in the fight against climate change.

## Individuals

This Scoping Plan not only projects ambitious availability of clean technology and energy, but also includes aggressive assumptions about consumer adoption of ZEVs, heat pumps, and other energy efficiency practices, among others. When it comes to climate change mitigation, the sum of the parts matters. Only when we add up the impacts of the choices we make do we understand the true impact on GHG emissions. Today, many Californians have opportunities to choose between driving a car, taking a bus, biking, or walking. Many can choose to install a heat pump or buy an electric cooktop. Together, we can increase these opportunities and pick the future we want. We can start or transform businesses that create clean jobs, innovate new technologies, or introduce new systems. We can engage with fellow workers to support durable paths for labor in a clean economy. And we can choose to engage with our community, tribes, and our governments to advocate for change, call out challenges, and propose solutions. Our choices will help determine California's climate future. Down one path is a future of climate impacts that will continue to worsen and further increase disparities across communities. Down the other is a future that avoids the worst impacts of climate change, improves air quality—especially for the most burdened communities—and fosters new economic and job opportunities to support a sustainable economy.

Importantly, we must acknowledge that historical decisions have resulted in health and opportunity gaps for residents in low-income communities and communities of color. Not everyone has the resources or access to make these choices—to buy a ZEV, install a heat pump, or use public transit to get to work. It is here that government can help. Government, at multiple levels, can fund programs and structure policies to provide consumers with more choice and to support them in adopting cleaner technology options. Whether through affordable energy rates or assistance in purchasing zero emission vehicles and appliances, we can use the transition to a carbon neutral economy as an opportunity to close some of these persisting opportunity gaps. By acting now, we can

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[539] Californiasolarcenter.org. Passive Solar History. *http://californiasolarcenter.org/old-pages-with-inbound-links/history-pv/*.
[540] Fuel Cell Store. History of Fuel Cells. *https://www.fuelcellstore.com/blog-section/history-of-fuel-cells?msclkid=04a19450c50211ec8d20f2afff4039fe*.

change our planet’s fate and build a more resilient, healthier, and equitable future for all Californians.