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THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION
1500 K STREET NW | SUITE 650 | WASHINGTON DC 20005

February 20, 2024

RE: International Council on Clean Transportation comments on the **Proposed Low Carbon Fuel Standard Amendments**

These comments are submitted by the International Council on Clean Transportation (ICCT). The ICCT is an independent nonprofit organization founded to provide unbiased research and technical analysis to environmental regulators. Our mission is to improve the environmental performance and energy efficiency of road, marine, and air transportation, in order to benefit public health and mitigate climate change. We promote best practices and comprehensive solutions to increase vehicle efficiency, increase the sustainability of alternative fuels, reduce pollution from the in-use fleet, and curtail emissions of local air pollutants and greenhouse gases (GHG) from international goods movement.

The ICCT welcomes the opportunity to provide comments on the Air Resources Board's Proposed Low Carbon Fuel Standard amendments. We commend the agency for its technical analysis and interest in continuing to improve the effectiveness of one of its flagship climate programs. Based on the content of the Initial Statement of Reasoning (ISOR) document, the comments below offer a number of technical observations and recommendations for ARB to consider in aligning the program with the goals of the 2022 Scoping Plan.

We would be glad to clarify or elaborate on any points made in the below comments. If there are any questions, ARB staff can feel free to contact Nik Pavlenko (n.pavlenko@theicct.org) and Dr. Stephanie Searle (stephanie@theicct.org).

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Summary of Comments

The LCFS program is designed to diversify California's transportation fuel pool and support the state's broader climate targets of economy-wide decarbonization and reducing dependence on petroleum.[1] Since 2011, the LCFS has undergone numerous rounds of revisions that have raised the carbon intensity (CI) reduction target and trajectory, expanded the list of eligible fuel pathways, and supported the expansion of zero-emission fueling infrastructure. The California Air Resources Board (CARB) is now administering another round of revisions to better align the program with the state's 2022 Scoping Plan.[2] These revisions were developed with input from numerous public workshops and engagement with the Environmental Justice Advisory Committee (EJAC) and summarized in an Initial Statement of Reasoning (ISOR) document released in December 2023.[3]

In its latest amendments, CARB has proposed to increase the annual CI reduction target to 30% in 2030 and make other program changes such as setting deliverability requirements on biomethane, phasing out avoided methane emissions crediting beginning in 2030, expanding project crediting for medium and heavy duty zero-emission vehicles, and obligating the volume of fossil jet fuel consumed on intrastate flights. CARB has also proposed introducing an auto-acceleration mechanism (AAM) and step down in the near-term CI target to address low and fluctuating credit prices in recent years. These changes are intended to put California on a path towards its long-term climate goals including an 85% GHG emission reduction target by 2045 and a path towards carbon neutrality.[4] Though we applaud CARB's proposal to extend the LCFS targets, we are concerned with the lack of safeguards to mitigate unintended emissions and market distortions that could undermine the policy's intended effects.

Our analysis finds that the "Proposed Alternative" is insufficient because it does not implement policy safeguards necessary to avoid unintended consequences to the climate impacts and efficacy of the program that were identified by CARB staff during the 2022-2023 Scoping Plan process. Safeguards discussed in previous LCFS workshops such as limiting the contribution of crop-based biofuels were not incorporated in the ISOR proposal, while proposed other safeguards such as phasing out avoided methane emissions crediting and aligning biomethane deliverability requirements with other fuel pathways are pushed far into the future and will have little relevance to the program's operation for over a decade.[5] The Proposed Alternative overestimates the GHG emissions attributable to the proposals and diverges from

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[1] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[2] Ibid.
[3] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[4] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp-es.pdf
[5] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf; https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf

previous LCFS rulemakings. Due to the recent ramp up of the program’s CI reduction trajectory, as well as potential interactions with the auto-acceleration mechanism, swift implementation of these safeguards is critically important to avoid unintended consequences of alternative fuel expansion.

Based on our review of CARB’s “Proposed Alternative”, we find that an alternative scenario is warranted. We recommend that this scenario incorporates elements of Alternative 1 and the Environmental Justice scenarios evaluated by CARB to safeguard against upstream emissions risk and align the LCFS with the goals of the 2022 Scoping Plan.

We recommend that CARB:

1) Set a cap on the volume of lipid-derived fuels credited under the LCFS program.

2) Phase out avoided methane emissions crediting for new projects within three years and align deliverability requirements for biomethane and bio-hydrogen pathways with the existing deliverability requirements for new electricity pathways.

3) Obligate jet fuel consumed within the California airspace starting in 2025, with a cap on lipid-based fuels crediting.

4) For pathways that utilize hydrogen as a feedstock such as e-fuels, subject the low-CI electricity used to produce the hydrogen to additionality and deliverability requirements consistent with the use of low-CI electricity for hydrogen, rather than low-CI electricity used as a process fuel.

5) Increase the scope of credit generation for transport electrification from charging infrastructure and fixed guideway public transit to simultaneously help the LCFS achieve equity goals and more ambitious target levels.

In the subsequent sections, we provide additional analysis and data from our review used to develop these recommendations.

The Proposed Approach Overestimates GHG Savings from Biomass-Based Diesel

Our analysis finds that the ISOR overstates the environmental benefits of the “Proposed Alternative.” This is largely because the methodology attributes the GHG savings of existing federal biofuels policies to the LCFS program. Over the past decade, the federal Renewable Fuel Standard (RFS) program has been the primary driver for BBD production in the country.[6] Under the RFS, the EPA sets annual volume mandates for biofuels, based on an assessment of national production capacity, economics, and existing federal and state subsidies. External policies like the LCFS also influence EPA’s volume projections. EPA has assessed what the 2023-2025 national biofuels market could look like in the absence of the RFS program in its supporting analysis to last year’s volume rulemaking.[7] By comparing fuel volumes from scenario tables with and without an RFS in place, it found that BBD volumes would be reduced by half in a “no RFS” scenario - reflecting market conditions that operate independently of the RFS (e.g., ethanol as an oxygenate). Given that California makes up nearly half of the national BBD market,[8] we can infer that a substantial portion of this growth in volumes is driven by the federal RFS. We present the estimated share of biofuel volumes for each major feedstock category that are attributable to the RFS program in Table 1.

Table 1. Biofuel volumes projected to be consumed in the U.S. that are attributable to federal RFS program. Calculated from Tables 2.1.5-2 and 3.1-4 of 2023 RIA

Volumes attributed to federal RFS	**2023**	**2024**	**2025**
Cellulosic biofuel	59%	63%	68%
BBD	54%	50%	50%
Other advanced biofuels	21%	21%	21%
Conventional renewable fuel	5%	5%	6%

The Draft Environmental Impact Analysis[9] is also a departure from CARB’s previous methodology. Previously, CARB only attributed emissions impacts beyond a 50% GHG reduction threshold to LCFS policy in updates to the 2018 LCFS rulemaking,[10]; i.e., emission reductions beyond the RFS’ minimum emissions reduction threshold for BBD that could plausibly have been incentivized by the LCFS program. In the 2024 Draft Environmental Impact Analysis, CARB counted the full GHG reductions of BBD as fully attributable to the LCFS and has thus overstated them. For these reasons, it is likely

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[6] https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf
[7] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OW2.pdf
[8] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OW2.pdf
[9] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appd.pdf
[10] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/15dayattf2.pdf

that CARB has also overstated the benefits that the LCFS has on regional air quality and health outcomes. Developing a more accurate estimate would require additional modeling to disentangle the effects of the LCFS from other climate and federal biofuels policies.

Using the CATS model default inputs shared at the July 2023 workshop and assuming a 30% carbon intensity reduction target for 2030, ICCT modeled the compliance trajectory of the LCFS and estimated the GHG reductions by fuel pathway.[11] Based on this default data, we estimate that the LCFS would generate approximately 35 million cumulative tonnes of GHG reductions from virgin vegetable oils from 2024-2034, after which virgin vegetable oil begins to generate deficits. Using CARB's previous methodology of only counting the GHG reductions above 50% (which no soy oil-derived BBD pathway exceeds), approximately 6% of the cumulative 558 Mtonne CO_2e reduction calculated by CARB in its Draft analysis from 2024 through 2045 would thus not have been attributed to the LCFS, significantly narrowing the GHG savings gap between the Proposed Alternative and Alternative 1. While higher BBD growth could provide some GHG reductions in the near-term, these reductions are offset by its uncertain and significant upstream emissions impacts and inability to guide California on a path towards net-zero decarbonization. We discuss these impacts in detail below.

The LCFS is Creating Market Distortions with the National Renewable Fuel Standard

We note that the LCFS's continued reliance on BBD feedstocks will necessarily impact other states' ability to meet their own climate goals. Based on a modeling run of the CATS model based on CARB's default inputs published in summer 2023, the modeling suggests that BBD consumption could peak at 2.1 billion gallons in 2025, or more than 70% of the federally mandated BBD volume that year. Current trends in California suggest that California could be at risk of overtaking the volume of BBD mandated under the RFS, which could depress RIN credit prices or trigger the AAM. If the renewable diesel boom in California pushes national BBD consumption beyond annual RFS mandates, this could have significant implications on RIN markets. Gerveni and Irwin have modeled the possibility of a "RIN cliff", where RIN prices fall to $0 per gallon if the BBD mandate becomes non-binding.[12] Because BBD is the marginal unit of compliance under the RFS, these price implications extend beyond the BBD RIN category. Without an increase in federal BBD mandates or a contraction in BBD supply, the value of BBD in the U.S. could steeply drop. This risk is even more likely if the AAM is activated given that current CATS modeling projections may understate the level of BBD required for LCFS compliance.

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[11] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops#:~:text=v0.2%20Technical%20Documentation-,CATS%20Example%C2%A0Inputs,-.

[12] https://farmdocdaily.illinois.edu/2023/05/is-the-us-renewable-fuel-standard-in-danger-of-going-over-a-rin-cliff.html

Furthermore, it is likely that the modeling used by CARB results in an under-estimate of LCFS-induced demand for virgin vegetable oils. The model baseline is tuned to 2022 consumption data and does not include the impact of the automatic-acceleration mechanism (AAM). We find that the model takes until 2025 to increase demand for BBD to present-day 2023 consumption, and the model's inability to assess the AAM prevents us from evaluating how high near-term credit prices could further accelerate demand for BBD in the near-term.

Consumption of BBD in California far exceeds its share of the national distillate fuel market. While California made up approximately 7% of national diesel consumption in the transportation sector in 2021,[13] it consumed approximately 44% of all BBD. Its share of renewable diesel consumption is far higher. Based on data from the 2023-2025 RFS impact analysis and California quarterly reports, we calculate that 87% of renewable diesel volumes credited under the RFS were consumed in California in 2022. Even more staggering, the EIA reports that California comprised 99% of national renewable diesel consumption in 2021.[14] If CARB does not curtail unchecked BBD growth in these current amendments, the LCFS will continue to draw BBD from other geographic regions into California. This trend will hamper the ability of other states to meet their own clean fuel standard (CFS) goals including Washington, Oregon, and the CFS newly announced in New Mexico.[15] Other state-level CFS programs in Minnesota and New York are currently under development.[16]

Supply Chain Certification of Crop-Derived Biofuels Fails to Address Indirect Land-Use Change Emissions

Over the past decade, BBD has exhibited the highest growth rate of all fuel pathways. BBD is on track to make up 46% of total credits in 2023, up from 8% in 2011.[17] Rapid growth in BBD consumption has also been followed by changes in the composition of the BBD feedstock market. Until 2021, nearly all BBD consumed in California was sourced from waste oil feedstocks such as used cooking oil (UCO), corn oil, and tallow that do not compete for land area across multiple economic markets. Although the California market was previously dominated by lower-CI BBD feedstocks, BBD derived from vegetable oils has made up a rapidly growing share of LCFS credits in recent years. Vegetable oil (primarily soybean oil) is projected to account for 17% of BBD

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[13] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_use_df.html&sid=US
[14] https://www.eia.gov/state/print.php?sid=CA
[15] https://www.env.nm.gov/wp-content/uploads/2024/02/2024-02-13-COMMS-Senate-passes-landmark-Clean-Fuel-Standard-Final.pdf
[16] https://www.dot.state.mn.us/sustainability/clean-transportation-fuel-standard-working-group.html; https://www.nysenate.gov/legislation/bills/2023/S1292
[17] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

volumes in 2023. Further, soy-BBD consumption more than doubled between 2021 and 2023 alone. We display the change in annual BBD volumes by feedstock category in Figure 1

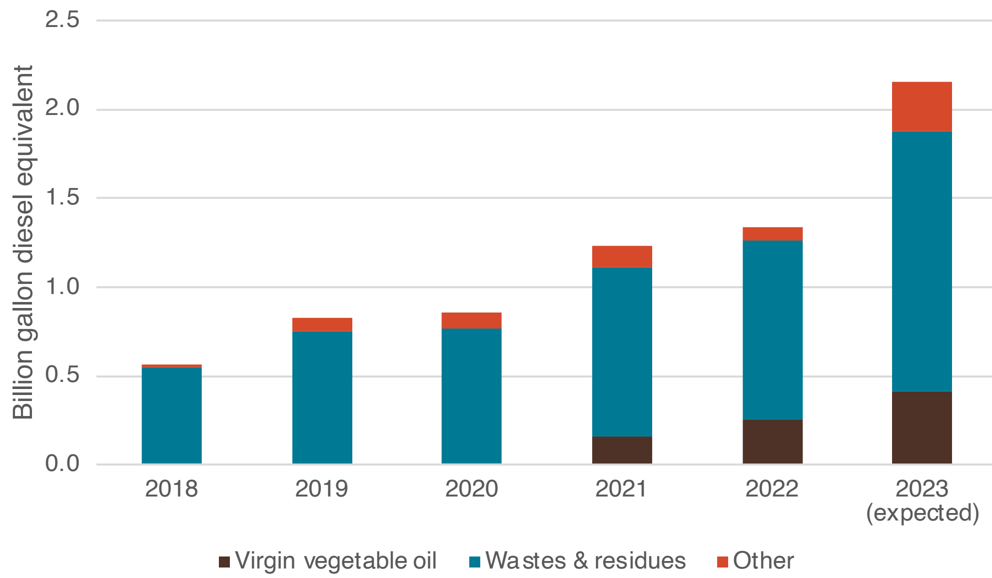

Figure 1. BBD volumes by feedstock category. Q1-Q3 2023 data is extrapolated through the end of the year.

There is no indication of this trend reversing or leveling off. EPA predicts that soybean crushing capacity could increase by more than 500 million bushels between 2022 and 2025,[18] equivalent to 770 million gallons in increased soybean oil BBD production. Industry associations including the American Soybean Association, National Farmers Union and Clean Fuels Alliance America are even more optimistic on soybean crush expansion. In comments submitted on the proposed 2023-2025 RFS volumes, these associations predicted that capacity commitments from soybean crushing facilities could result in 700-800 million gallons of additional BBD by the end of 2025.[19]

Gerveni and Irwin (2023) estimate that renewable diesel nameplate capacity could reach 7.4 billion gallons over the next decade, up from 4.1 billion gallons in 2023, and 0.8 billion gallons in 2020.[20] Similarly, the Energy Information Administration (EIA) estimates that RD capacity could more than double between 2023 and 2025 as a result of favorable state and federal biofuels policy and tax credits allocated under the Inflation

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[18] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OKN.pdf
[19] https://soygrowers.com/wp-content/uploads/2023/02/EPA-RFS-2023-2025-ASA-Comments.pdf; https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0805; https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0595
[20] https://farmdocdaily.illinois.edu/2023/03/overview-of-the-production-capacity-of-u-s-renewable-diesel-plants-for-2023-and-beyond.html

Reduction Act (IRA).[21] The majority of this growth will come from retrofits of existing refineries distributed along the U.S. West Coast, Gulf, and mountain regions.

The LCFS program's accelerating reliance on biomass-based diesel to meet the program's greenhouse gas targets is at odds with the emerging evidence on the market-mediated GHG emissions from growing biofuel demand using purpose-grown crops. The Draft Environmental Impact Analysis overlooks the magnitude of emissions uncertainty associated with crop-based biofuels production and overcounts emissions reductions attributable to the LCFS program. This problem is particularly relevant to BBD fuels due to their significant upstream market and environmental impacts that are not well accounted for in supply chain (attributional) life-cycle assessment (LCA). Though CARB has evaluated the indirect land-use change (ILUC) emissions attributable to vegetable oil-derived fuels, recent studies suggest that these emissions may be understated, and the existing ILUC emission factor used in the LCFS may not be a sufficient safeguard.

We find that CARB's ILUC assessment may underestimate soy-BBD emissions significantly. When soybean oil is diverted from food, feed, and oleochemicals markets it is often substituted with palm oil;[22] this greatly increases its upstream emissions impacts because palm oil is often grown on high-carbon stock land. In its recent RFS triennial review, EPA notes that there remains "potential for low-cost palm oil from ecologically sensitive areas in Southeast Asia to "backfill" diverted soybean oil from international vegetable oil markets." This risk is "especially [likely] if RFS program total biofuel mandates increase in the future".[23] Due to soy-palm substitution and pressure that soy expansion places on other markets, soy BBD's ILUC emissions may even exceed that of fossil fuel.

Despite years of dedicated research, ILUC modelers are no closer to reaching consensus around the upstream land-use impacts of biofuels production since the field emerged in the mid-2000s. Persistent scientific uncertainty and risk of deforestation has lead jurisdictions such as the European Union and United Kingdom to cap or limit the contributions of crop-based fuels within major fuels regulations.[24] In a 2022 report, the National Academies of Sciences, Engineering, and Medicine concluded that "substantial uncertainties remain on many key components of economic models used to assess [LUC] impacts" in their comprehensive review of LCA methodology.[25] The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) incorporates LCA results from two different models in an attempt to account for the range of results across

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[21] https://www.eia.gov/todayinenergy/detail.php?id=55399
[22] https://www.sciencedirect.com/science/article/pii/S0301421518307924
[23] https://cfpub.epa.gov/ncea/biofuels/recordisplay.cfm?deid=353055 (p. IS-22)
[24] https://data.consilium.europa.eu/doc/document/PE-29-2023-INIT/en/pdf; https://assets.publishing.service.gov.uk/media/6424782560a35e00120cb13f/pathway-to-net-zero-aviation-developing-the-uk-sustainable-aviation-fuel-mandate.pdf
[25] https://nap.nationalacademies.org/catalog/26402/current-methods-for-life-cycle-analyses-of-low-carbon-transportation-fuels-in-the-united-states

different inputs and methodologies.[26] Although modeling of starch and sugar-based pathways have reached relative alignment for the purposes of CORSIA, ILUC modelers assessing oilseed based pathways found substantial differences across models ranging from 7 to 90 gCO_2e/MJ for various oilseed-derived biofuel pathways.[27] Depending on which model is used to assess ILUC emissions, some pathways were found to have higher emissions than the fossil fuel baseline.

The Environmental Protection Agency (EPA) released a technical modeling comparison document last year that highlights the persistent scientific uncertainty of ILUC modeling.[28] As part of the exercise, EPA compared five models including their modeling structure, spatial and temporal resolution, representation of land types, and trade dynamics. Despite harmonized inputs, the models varied greatly in their representation of global economic activity and, notably, their ILUC emissions estimates. The analysis concluded that "the variability of LUC estimates significantly influences variability in overall biofuel GHG estimates." Further, EPA found that level of uncertainty is particularly high for soybean oil due to its fungibility with other vegetable oils including palm oil in other markets. We display EPA's results from its corn ethanol and soybean biodiesel scenario runs across the five models in Figure 2. ILUC emissions for soybean biodiesel range between 9 and 280 gCO2e/MJ while ILUC emissions for corn range between -1 and 29 gCO2e/MJ. Removing the ADAGE model as an outlier, soybean biodiesel results range by 49 gCO2e/MJ, more than half the certified CI of fossil diesel in California.

[26] https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA_Eligible_Fuels/CORSIA_Supporting_Document_CORSIA%20Eligible%20Fuels_LCA_Methodology_V5.pdf
[27] Ibid.
[28] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf

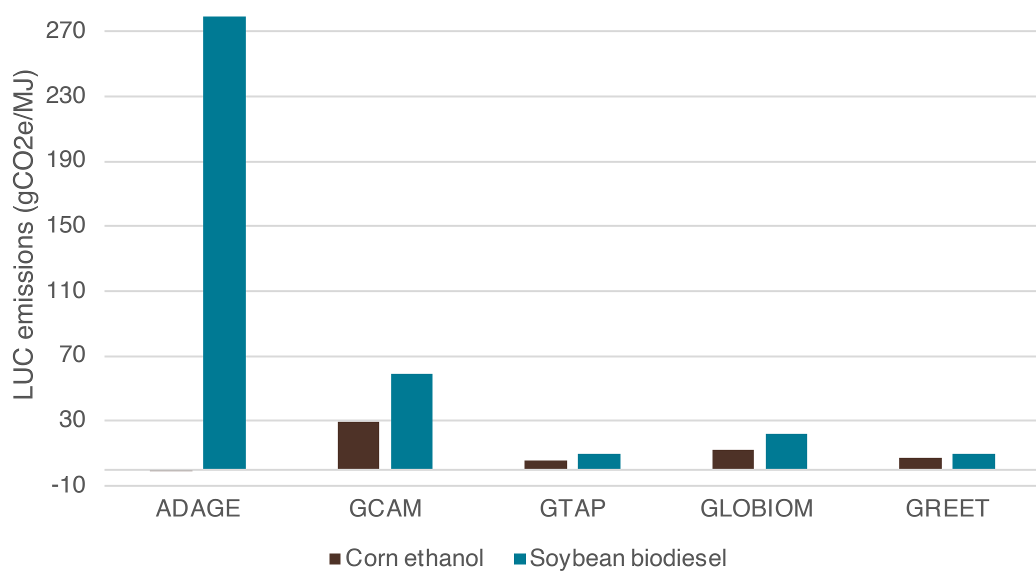

Figure 2. Land-use change emissions from EPA Modeling Comparison exercise

CARB uses a version of the Global Trade Analysis Project (GTAP-BIO) model in its 2015 ILUC assessment that modeled the impacts of demand shocks for crop-based biofuels on commodity prices and net global land conversion. Based on these modeling runs, CARB adopted an ILUC value of 29.1 gCO_2e/MJ for soy biodiesel. GTAP-BIO has been the subject of significant academic debate due to parametric assumptions such as its modeling of unmanaged forest land and high rates of yield intensification.[29] Most contentiously though, GTAP-BIO assumes that cropland expansion is likeliest to occur onto land parcels classified as "cropland pasture" and that this type of land conversion sequesters rather than releases carbon.[30] This assumption conflicts with definitions used by the EPA that assume "cropland pasture" is land currently in a pasture state[31] and thus will result in soil organic carbon (SOC) loss when converted to cropland. As a result, the ILUC emissions adopted by CARB likely underestimate the upstream emission impacts associated with biofuel expansion.

CARB has acknowledged that "a rapid increase in oil crop demand for biofuel production could potentially add pressure to convert forested land or other land types into biofuel crop production." Rather than set a cap on high-risk feedstocks, CARB has proposed that biofuel producers adhere to a sustainability certification scheme (SCS) where independent auditors must track feedstocks to their point of origin and verify their environmental attributes to be certified. This proposal is aligned with other sustainability requirements set forth under the EU's Renewable Energy Directive (RED II) and

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29 https://theicct.org/wp-content/uploads/2023/09/ID-16-Briefing-letter-v3.pdf
30 https://www.sciencedirect.com/science/article/abs/pii/S0959652620307630
31 US EPA. "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis," February 2010.

international CORSIA program. However, the SCS guardrail only applies to crop and forestry-based feedstocks; thus, excluding UCO supply chains with documented cases of fraud. Member States within the European Union have prosecuted several cases of UCO fraud, arising from UCO's high credit value under their implementation of the RED II.[32] In these examples, companies that were certified under SCSs forged the quantity of waste-based biofuel sold on the market or forged the makeup of these fuels entirely. An investigative report submitted to the European Commission found that the Dutch company Sunoil forged SCS certificates in 2020 of an unknown volume that credited crop-based biofuels as waste-based; the investigation is still underway.[33] Executives of the former company, Biodiesel Kampen, were arrested for fraud for falsely reporting the volumes of waste-oil fuel sold on the market. It is likely that employees may have also falsely labeled crop-based biofuel as waste-based to receive credit incentives.

The EU's experience has found that third-party verification schemes are an ineffective tool to address the environmental and social risks of biofuels. The European Anti-Fraud Office investigated a case involving numerous companies where 150,000 tonnes of virgin soy oil exported from the U.S. was fraudulently labeled as UCO to avoid anti-dumping fees and exploit national-level renewable energy incentives. A producer in the U.S., Greenworks Holdings LLC, also forged quality tests for UCO biodiesel and overstated production quantities to receive higher credit value under the federal Renewable Fuel Standard (RFS).[34]

While SCSs can help verify material and emission inputs across the fuel supply chain, supply chain certifications are fundamentally not suited to address the significant and uncertain environmental harm associated with market distortions from BBD demand. Certification schemes, even if properly implemented, cannot measure or address ILUC. Thus, our analysis finds that it is critical that the volume of BBD feedstocks are capped at manageable levels. This exact threshold can be debated but should reflect a feedstock's total availability accounting for competition from other sectors plus marginal growth in domestic production that is proportionate to California's share of the national distillate fuel market. Using this methodology, a previous ICCT analysis has suggested capping the contribution of lipid-based fuels, including vegetable and waste oils, at 1.2 billion gallons.[35] California has already far exceeded this supply threshold and is projected to produce 2.2 billion gallons of lipid-based BBD in 2023.

Although California has already exceeded its proportional share of domestic BBD supply, an energy or volume cap can help contain future unchecked growth in BBD markets. Given the substantial increase in BBD volumes since 2021 and difficulty associated with scaling down existing production, we recommend capping the

[32] https://op.europa.eu/en/publication-detail/-/publication/ec9c1003-76a7-11ed-9887-01aa75ed71a1/language-en
[33] https://op.europa.eu/en/publication-detail/-/publication/ec9c1003-76a7-11ed-9887-01aa75ed71a1/language-en
[34] https://theicct.org/wp-content/uploads/2023/02/US-UCO-potential_fs_final.pdf
[35] https://theicct.org/wp-content/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf

contribution at levels consistent with Alternative 1, which implements a roughly 2-billion-gallon cap on lipid-derived fuels starting in 2025. As explained above, the difference in emissions and implementation costs between this scenario and the Proposed Approach is substantially narrower than modeled by CARB, and this would reduce unintended climate impacts and market distortions. Further, we recommend that CARB extend the SCS requirement to all feedstocks to mitigate fraud risk from UCO imports.

Implement livestock methane regulations and accelerate the phaseout of avoided methane emissions crediting

Avoided methane crediting has been used as a mechanism to comply with the state's Short-Lived Climate Pollutant (SLCP) strategy and precursor Senate Bill (SB) 1383 which requires that California reduce methane emissions 40% from 2013 levels by the year 2030. In place of developing binding regulations on in-state farms, previous CARB statements suggest that the LCFS is a sufficient incentive to meet the SLCP targets.[36] Notably, this methodological assumption is only applied to livestock and organic waste digester projects where methane capture is considered voluntary rather than legally required.[37] Livestock digester projects made up an estimated 90% of biomethane credit generation under the LCFS in 2023 while accounting for less than half of volumes (Figure 3).

Biomethane is consumed in a small number of natural gas vehicles (NGVs) that account for 5% of heavy-duty fuel consumption in the state.[38] NGV fuel consumption will decline in the coming decades due to the implementation of the Advanced Clean Trucks (ACT) and Advanced Clean Fleets (ACF) rulemakings that regulate a minimum share of zero-emission vehicles within California's medium and heavy-duty (MHDV) transportation fleet.[39] Despite its small role in the MHDV sector, biomethane crediting within the LCFS has accelerated in recent years. This has occurred while the delivered share of total volumes credited under the program have remained nearly constant. Biomethane is projected to make up 18% of LCFS credits and 5% of volumes in 2023, extrapolating from data from CARB's recently published Q3 report through the end of the year.[40]

The growing divergence between biomethane credits and volumes is due to the high LCFS incentive that biomethane receives when it is utilized as transportation fuel. When

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[36] https://ww2.arb.ca.gov/sites/default/files/2022-01/LCFS%20Petition%20Response%202021.pdf
[37] https://www.law.cornell.edu/regulations/california/17-CCR-95488.9
[38] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[39] https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets; https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks/about
[40] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

assessing the lifecycle impact of some biomethane pathways, CARB assumes that methane emissions would be vented to the atmosphere in the absence of an LCFS policy signal. We illustrate growth in biomethane volumes and credits by feedstock in Figure 3.

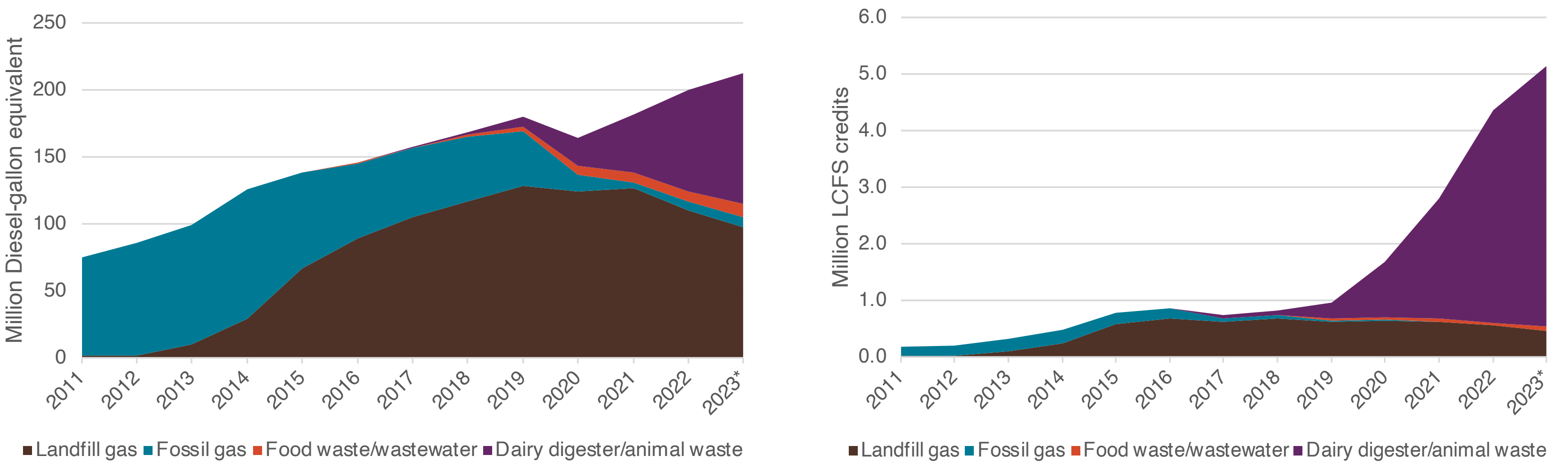

Figure 3. Share of CNG volumes by feedstock type (left); Share of CNG credits by feedstock type (right)

Rapid growth in livestock digester projects in California is motivated by its significant financial incentives. We find that active swine projects have an average CI of -406 gCO_2e/MJ while active dairy projects have an average CI of -285 gCO_2e/MJ based on data reported in the LCFS current pathways spreadsheet,[41]. This is equivalent to a $6.66/diesel-gallon equivalent(DGE) and $5.03/DGE credit value in 2023, respectively, assuming an $100/metric tonne credit price.[42] If biomethane is later converted to bio-hydrogen it receives an even higher credit incentive per volume of fuel due to hydrogen's 1.9x energy economy ratio (EER) in MHDV applications.[43] Using CARB's LCFS credit price calculator, we find that the value of bio-hydrogen could even exceed $5/kg assuming current credit prices, nearly double the tax incentive under the 2022 Inflation Reduction Act (IRA). We present common biomethane pathways, their average CI, and associated credit value in 2023 in Table 2. Pathways with negative emission CIs receive the highest LCFS credit value while pathways with higher average CIs such as landfills and wastewater plants receive a more moderate credit value.

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[41] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[42] https://ww2.arb.ca.gov/sites/default/files/2022-03/creditvaluecalculator.xlsx
[43] https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

Table 2. Average project CI value and credit values for certified biomethane pathways in 2023. Assumes $100/mt LCFS credit price

Feedstock pathway	Average CI (gCO_2e/MJ)	Credit value ($/MMBTU)	Credit value ($/DGE)
Landfill gas	62.6	$2.81	$0.36
Fossil NG	79.2	$1.05	$0.13
Wastewater	49.0	$4.24	$0.54
Food waste	-54.1	$15.11	$1.93
Organic waste	16.7	$7.64	$0.97
Swine manure	-406.2	$52.27	$6.66
Dairy manure	-285.2	$39.5	$5.03

Digester projects are also eligible for federal and state-level grant funding to reduce the cost of methane capture. The U.S. Department of Agriculture (USDA) offers loan financing under the Rural Energy for America Program (REAP) to cover up to 75% of eligible costs for energy projects.[44] Since 2015, the California Department of Food and Agriculture (CFDA) has awarded $227 million in funding for dairy digester projects concentrated in the Central Valley.[45] Dairy biomethane is also eligible for RIN credits, which have traded at a value of $2.50 per gallon ethanol equivalent ($4.1/DGE) over the last 5 years.[46] Between 2025 and 2027, the IRA 45Z tax credits will provide another funding stream of up to $1.00 per DGE for dairy biomethane consumed as a transportation fuel. In total, this amounts to a staggering incentive of ~$11-$12.50 per DGE for biomethane derived from dairy and swine digesters, assuming LCFS credit prices from Table 2 above.

The combination of high-value incentives from multiple overlapping policies and jurisdictions poses a particularly strong additionality risk for pathways certified with avoided methane emissions. Though CARB has generally avoided assessing the additionality of fuels delivered under the program, biomethane pathways pose a unique risk because of a combination of factors, namely 1) their very high negative emissions attributable to out-of-sector behavior, 2) the lack of meaningful deliverability requirements meaning that these fuels aren't necessarily consumed in California or in the transportation sector (as discussed in the subsequent section), and 3) the sheer size of the combined policy incentives for these fuels. While it can be argued that a biofuel consumed in California can benefit from a combination of policies to motivate its production and reduce its CI, that argument has less merit for crediting a unit of natural

[44] https://www.rd.usda.gov/programs-services/energy-programs/rural-energy-america-program-renewable-energy-systems-energy-efficiency-improvement-guaranteed-loans
[45] https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Program_Level_Data.pdf
[46] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

gas paired with the attributes of an out-of-state dairy farm. Given the accelerating role of these pathways in the LCFS and their out-of-scale contribution to the program, implementing guardrails in this rulemaking would help to ensure that the LCFS is not diluted by GHG reductions whose attribution to the program is difficult to demonstrate.

We find that numerous digester projects that upgrade biogas to renewable natural gas (RNG) were already capturing methane independently of the LCFS program. These producers receive negative emissions credits for simply diverting biogas feedstock from existing applications to the transport sector rather than capturing methane that would have otherwise been vented to the atmosphere. For example, ICCT submitted comments on FirstElement Fuel's LCFS pathway application that highlights the lack of additionality for biomethane-based project crediting.[47] The candidate dairy farms were previously producing electricity on-site with excess transmitted to the local electric grid. Project data indicates that the digester was installed in 2010, far before the facility began upgrading biogas to transportation fuel.[48] Despite this pre-existing baseline, the facility operators assumed that methane would be vented to the atmosphere under a counterfactual scenario in their pathway application, later approved by CARB. This counterfactual scenario is simply not credible, and neither are the GHG emission reductions credited to the LCFS for this pathway.

Biomethane capture in anaerobic digesters will remain an effective method to reduce methane emissions but it is critical to recognize that the LCFS is often not the driver of this step and digesters are often installed or were installed years ago for other reasons. Thus, phasing out avoided methane crediting in the LCFS as soon as possible will help to "right-size" the value of RNG pathways compared to their genuine effect of reducing lifecycle GHG emissions and displacing fossil fuel consumption. We recommend that CARB phase out avoided methane credits at the end of existing pathways' current 10-year crediting cycle and within three years for new applications to help prevent crediting biomethane pathways that are not additional. It generally takes up to 2 years for developers to plan and construct new digester projects,[49] so this timeline would offer flexibility to developers that anticipated negative emissions crediting within their project economics. Following a similar timeline, the IRA 45V tax credit has set a vintaging requirement that renewable energy generation facilities must be built no earlier than 3 years before the tax credit takes effect to avoid crediting projects that are non-additional.[50]

Using the Argonne National Lab Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model, we estimate the emissions for dairy biogas to be approximately 19 gCO_2/MJ, assuming that the methane reductions and soil carbon

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[47] https://www.arb.ca.gov/lists/com-attach/980-tier2lcfspathways-ws-Vj8GY1c1ACcLUlc0.pdf
[48] https://martinenergygroup.com/wp-content/uploads/2022/08/2MCR_QualificationsStrengths_Final.pdf
[49] https://www.biogasworld.com/biogas-faq/#:~:text=For%20a%20moderate%20to%20large,have%20a%20functioning%20biogas%20plant.
[50] https://www.govinfo.gov/content/pkg/FR-2023-12-26/pdf/2023-28359.pdf

sequestration from digestate are not attributable to the LCFS (i.e. that a digester would still have been used in the counterfactual scenario).[51] This change still represents an approximately 80% GHG reduction relative to conventional, petroleum-derived fuels but more accurately reflects the emissions reductions from displacing fossil fuels.

Although capturing methane from dairy digesters is a laudable goal, there are other methods to meet the 40% reduction target of the SLCP. Changes to manure management practices and livestock diets can help reduce methane reduction at the source.[52] It may also be preferable to implement a regulation with a carbon border adjustment mechanism[53] to ensure that dairy products produced outside of California are treated consistently with those produced in-state. The EPA has detailed strategies that agricultural producers can pursue depending on the size of their operations and relative costs.

CARB's proposed phaseout dates of 2040 for biomethane and 2045 for bio-hydrogen are completely insufficient to prevent avoided methane credits from distorting the climate goals of the LCFS. Though the scenario modeling published by CARB indicates that these pathways will be phased out completely after 2040, this modeling does not take into account the opportunities for existing pathways to recertify for multiple, 10-year periods. For example, RNG pathways with avoided methane emissions credits that are certified before 2030 may qualify for up to three, 10-year credit periods. Furthermore, the Draft analysis does not evaluate the transition from dairy RNG pathways (which are separated in the results) to dairy biomethane electricity and dairy biomethane hydrogen pathways.

In summary we recommend that the phaseout of avoided methane emissions crediting takes effect by the end of the 10-year crediting period for certified projects and that avoided methane emissions credits are phased out for new projects within the next 3 years. These changes from the current ISOR proposal are critical to align the significant subsidies allocated to biomethane with its climate impact when consumed as a transport fuel.

Book-and-claim biomethane crediting sustains out-of-state and out-of-sector emissions crediting, diluting the LCFS's impact on California's transportation sector

By conflating methane reductions achieved under the SLCP strategy with the book-and-claim structure LCFS program, CARB has overstated the ability of biomethane to

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[51] Argonne National Lab, 2021 "Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model",https://greet.es.anl.gov/; assuming 100% dairy cow-derived manure, California electricity grid mix, for renewable natural gas as an intermediate fuel.
[52] https://www.epa.gov/agstar/practices-reduce-methane-emissions-livestock-manure-management
[53] https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

displace petroleum and achieve the state's broader decarbonization goals. Book-and-claim decouples fuel consumption from fuel production via the purchase and trade of environmental attributes; thus, it does not require any physical traceability of injected fuel. In many cases, RNG projects credited under the LCFS are located outside of California that have no direct impact on California's greenhouse gas (GHG) emissions or in-state agricultural practices. In other words, natural gas suppliers may gain revenue from LCFS credits for a unit of fossil gas produced and consumed in California (often in non-transportation uses) with an equivalent unit of renewable natural gas (RNG) produced across the country and injected into the national natural gas transmission grid.

Based on existing pathways certified under the LCFS, we find that **all** active landfill gas and swine digester projects credited under the LCFS are located outside of California while 48% of dairy digester projects and 83% of wastewater projects are located outside of the state based on CARB project data.[54] Similarly, CARB has found that, in 2022, the majority of RNG reported under the LCFS program came from "resources injected into the North American natural gas pipeline outside of California."[55]

We review the geographic makeup of biomethane derivative projects including bio-hydrogen and low-CI electricity in Figure 4. Out-of-state project crediting is particularly relevant for dairy manure projects that receive a highly negative CI under current LCFS methodology. We focus on dairy manure as a feedstock since dairy manure-derived biogas makes up the highest number of active biomethane, bio-hydrogen, and bio-electricity projects credited under the LCFS. We find that all dairy manure-derived bio-hydrogen projects are sourced from digesters located outside of California while roughly half of dairy biomethane projects are located outside of the state. We present the share of active dairy biomethane and derivative projects located within and outside California from CARB's pathways spreadsheet in Figure 4.

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[54] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx
[55] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

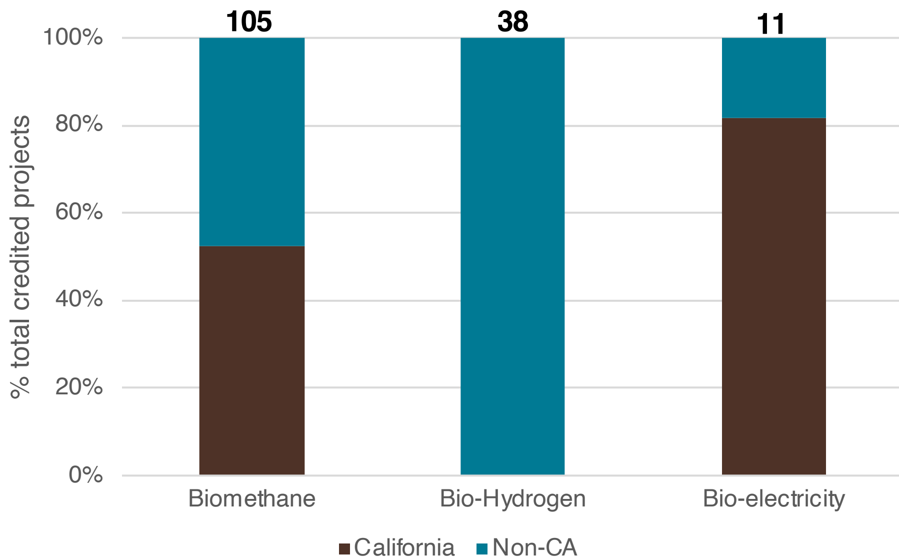

Figure 4. Share of dairy biomethane and derivative projects receiving LCFS credits located in and outside California. Total number of active projects are bolded at the top of each column.

CARB has proposed setting deliverability requirements on biomethane to better align project crediting with the state's methane reduction targets and address the recent rise in book-and-claim crediting. Deliverability requirements stipulate that biomethane must flow through "common carrier pipelines that physically flow within [or toward] California…50% of the time on an annual basis" beginning in 2041 for biomethane and 2046 for bio-hydrogen. The proposed language is consistent with deliverability requirements that biomethane-based electricity must adhere to under the state's Renewable Portfolio Standard (RPS); however, the ISOR does not specify how these requirements would translate to the natural gas grid and CARB has not provided further information on how it would be implemented and to what extent it would constrain the existing system. A simple geographic deliverability requirement will be more transparent, easier to implement, and is precedented from the deliverability requirements for low-CI electricity. Drawing from an analysis conducted by the U.S. Department of Energy (DOE) for 45V tax credit implementation, we recommend that CARB limit geographic eligibility for biomethane to the states of Washington, Oregon, and California, as this would be roughly consistent with the geographic deliverability for electricity proposed for 45V.[56] Alternatively, CARB can reference geographic zones from the U.S. natural gas transmission network to set its deliverability boundaries.[57]

We note that the deliverability requirements for biomethane for hydrogen specifically are far less stringent than those for low-CI electricity derived hydrogen. Despite achieving a higher theoretical credit price than green hydrogen, green hydrogen made from low-CI electricity must satisfy a more rigorous series of requirements to ensure geographic

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[56] https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen
[57] https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html

deliverability, that low-CI electricity comes from new generation, and no double-counting. In contrast, biomethane producers who sell their environmental attributes to existing grey hydrogen producers must only demonstrate the retirement of environmental attributes. Thus, a pathway that enables further use of existing natural gas SMR technology generates higher credit values in the LCFS and has looser book-and-claim requirements than a green hydrogen pathway that involves deploying new electrolyzer technology. We recommend that CARB set deliverability requirements on bio-hydrogen that are consistent with other biomethane pathways. That is, implemented within the next three years and adherent to the same geographic boundaries.

The deliverability requirements proposed in the ISOR also fall short of initiating any meaningful change to current operating conditions. This is due to significant implementation delay and looser guidance granted to hydrogen producers. CARB has noted that this delay is intentional to encourage a "rapid buildout of biomethane capture projects" before the end of the decade to meet the state's methane reduction goals. However, attributing biomethane capture to the LCFS program belies the reality that majority of these emissions reductions occur out of state and outside the transportation sector. Credited RNG volumes may also begin to exceed the quantity of natural gas consumed in California's transportation sector, further stretching the plausibility of the argument that RNG contributes to reducing California's transportation GHG emissions. Previous ICCT analysis has found that RNG volumes credited under the LCFS accounted for 98% of natural gas vehicle consumption in California in 2021.[58] As demand for CNG declines even further, new RNG production will have no little to no impact on displacing in-state petroleum consumption and meeting the goals of the 2022 Scoping Plan.

In summary, we recommend that CARB implement stronger deliverability requirements for all pathways derived from biomethane within the next three years to prevent subsidizing out of sector emission reductions within an in-state transportation policy. For pathways that are already certified, we recommend that deliverability requirements take effect at the end of the current 10-year crediting period.

Obligate fossil jet fuel as a deficit-generating fuel before 2028 and paired with a cap on lipid-based fuels

CARB has proposed obligating jet kerosene as a deficit-generating fuel beginning in 2028. This will increase crediting opportunities for sustainable aviation fuel (SAF) and encourage economic growth in a budding California SAF market. Due to the small size of the volume obligation, this growth will be limited. Without expanding the obligation scope to cover all inter-state jet fuel, it will also require that other transport sectors

[58] https://theicct.org/wp-content/uploads/2023/05/california-rng-outlook-2030-may23.pdf

continue to shoulder the burden of decarbonizing the state's aviation emissions. If LCFS amendments do not incentivize sufficient quantities of SAF, the aviation sector can source credits from sectors that over-comply with their annual CI reduction targets to meet annual compliance.[59]

California has signaled stronger support for SAF in earlier proposals that are notably less ambitious in the ISOR. In 2021, California legislature passed AB 1322 that set a 20% SAF blending target by 2030, approximately 1.5 billion gallons.[60] This bill was later vetoed by Governor Newsom on the grounds that the LCFS was already an effective policy lever to meet these goals.[61] Absent any proposed amendments, ICCT research has found that the LCFS alone is an insufficient tool to promote SAF uptake in California.[62] Study authors found that obligating intra-state aviation would only expand the LCFS program by 5% based on the quantity of deficits generated on intra-state flights. Pavlenko and Mukhopadhaya estimate that fuel consumed on intra-state flights accounts for roughly 6% of jet fuel uplifted in California.[63] At a maximum, that level of obligation would deliver a maximum of approximately 113 million gallons of SAF production by 2030 assuming that aviation obligations are met in-sector rather than through out-of-sector credits from renewable diesel or electric vehicle charger.

In comparison, CATS modeling suggests that jet fuel deficits will make up 1.8% of total deficits (0.76 million tonnes CO_2e) in 2030 under a 30% CI reduction target. Jet fuel makes up approximately 0.7% of deficits (0.23 Mt CO2e) under the baseline 20% CI reduction target. If jet fuel was obligated at an earlier date, this could generate an additional 2.6 million tonnes in CO_2e deficits between 2025 and 2027 under the proposed scenario. This corresponds to approximately 500 million gallons of cumulative SAF production, based on the average carbon intensity of SAF consumed in California in 2021.

If California were to obligate the entirety of jet fuel consumed over its airspace, this could motivate SAF production even further. We analyze what this obligation might look like based on routing data from California airports, using an updated version of the Global Aviation Carbon Assessment (GACA) model developed by Graver et al. (2020.)[64] Jet fuel consumed over the California airspace is approximately 3 times the magnitude of fuel consumed on intra-state flights (i.e., those that begin and end in California). We source jet fuel deficit quantities directly from the CATS model and calculate SAF production assuming a conversion ratio of 0.005 tonnes of offset CO_2e per gallon. Our estimates likely overstate SAF production by assuming that SAF credits fully offset the quantity of jet kerosene deficits. In practice, the quantity of SAF would be lower due to the relatively lower cost of using out-of-sector credits.

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59 https://theicct.org/wp-content/uploads/2023/01/ca-aviation-decarbonization-jan23.pdf
60 https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1322
61 https://www.gov.ca.gov/wp-content/uploads/2022/09/AB-1322-VETO.pdf?emrc=7598b6
62 https://theicct.org/wp-content/uploads/2023/01/ca-aviation-decarbonization-jan23.pdf
63 Ibid.
64 https://theicct.org/publication/co2-emissions-from-commercial-aviation-2013-2018-and-2019/

We review results from the August 2023 CATS model under a baseline (20% CI reduction, proposed (30% CI reduction), and proposed with expanded obligation the entire CA airspace scenario in Figure 5. These scenarios assume that jet fuel is obligated beginning in 2025, 3 years ahead of the published ISOR proposal. We find that near-term SAF production is significant under the proposed scenario (30% CI reduction) and increases to 198 million gallons in 2030 while SAF production gradually increases to 49 million gallons under the baseline scenario (20% CI reduction). Obligating the entirety of the CA airspace would result in far higher SAF production. We this obligation could result in 1.1 billion gallons of new SAF production in 2030.

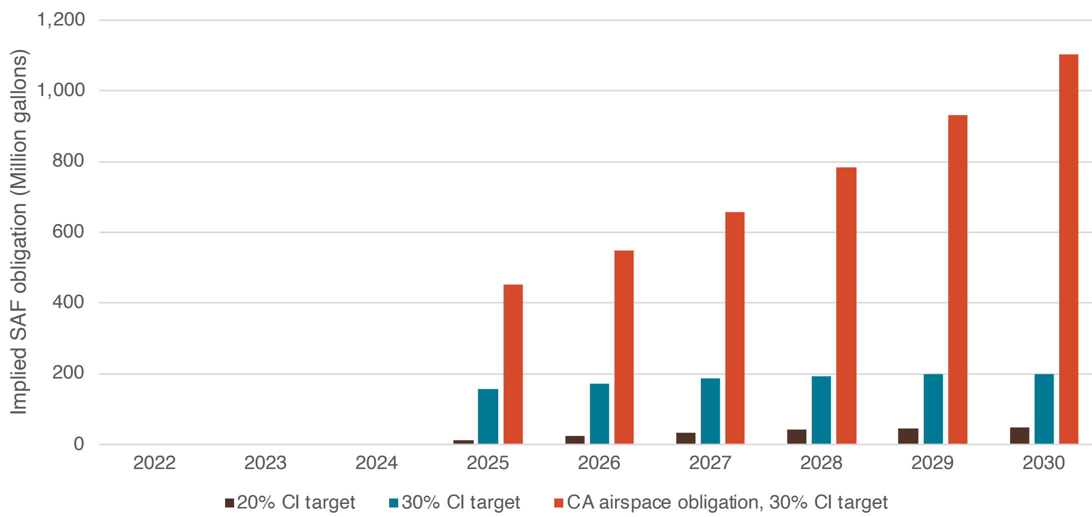

Figure 5. Estimated SAF production to offset jet kerosene deficit generation under three LCFS scenarios

Obligating jet fuel demand could help incentivize SAF production in California but would fall short of the legislative intent of AB 1322 across all scenarios. If CARB waits until 2028 to implement this obligation, this will reduce the cumulative production of SAF by 500 million gallons based on the proposed scenario and 1.66 billion gallons, assuming an obligation of the entire CA airspace.

While an increase in SAF can deliver public health and emissions reduction benefits, it is important that this growing fuel market does not exacerbate upstream emissions impacts from other transport sectors. SAF is often co-produced with renewable diesel at bio-refineries and thus is sourced from the same waste and virgin vegetable oil feedstocks. This increases demand for lipids that are already in limited supply and could exacerbate unintended emissions consequences associated with biofuel production. These risks include ILUC, plummeting RIN prices, and waste oil fraud as discussed above.

To summarize, though we support expanding the scope of the LCFS to include the aviation sector, we caution that it must be done without exacerbating the underlying problems in the LCFS. If aviation is obligated without a separate safeguard on lipid-based fuels, this could undermine the GHG emission and public health benefits of regulating aviation emissions. Thus, we recommend that CARB obligate jet fuel consumed over the entire CA airspace to spur growth in nascent SAF markets and deliver public health benefits but only if this obligation is paired with a cap on the consumption of lipid-based fuels. We also recommend that this obligation take effect in 2025 to increase cumulative SAF output and signal earlier support for the production scale-up of advanced fuel pathways.

Establish criteria for low-CI electricity used to produce e-fuels consistent with criteria for green hydrogen production

In the proposed amendments to the LCFS, CARB staff propose new requirements for the attribution of low-CI electricity used as a transportation fuel, direct air capture, and for hydrogen used directly as a transport fuel. These requirements are a welcome change from the previous guidance for the crediting of low-CI electricity under the LCFS, and will help to ensure that low-CI electricity is not being diverted from existing uses by ensuring that it is new production, deliverable within the same grid region, and that renewable energy attributes are not double-claimed.

However, we note that as written, the current guidance will restrict the use of e-fuels made from low-CI electricity, as these are not included in the current language. Thus the proposal would effectively restrict low-CI electricity from being eligible for attribution unless it was supplied via a direct electricity connection. However, it is likely that as with most green hydrogen production, grid-connected projects will have greater economic competitiveness due to a higher capacity factor.[65] Therefore, to provide more flexibility for e-fuel pathways based on converting green hydrogen into other fuels, we recommend that CARB treat these pathways' use of low-CI electricity consistent with green hydrogen and direct air capture. This will still maintain crucial safeguards on project vintage, deliverability and double-counting, while providing necessary flexibility for these projects to use renewable electricity supplied via the grid.

Expand Opportunities for ZEV crediting

The Proposed Alternative relies heavily on virgin vegetable oils and avoided emissions from biomethane to meet 2030 targets, despite these pathways' sustainability risks and the potential for over-attribution of GHG savings to the LCFS program. In CARB's Draft analysis, both Alternative 1 and the EJ scenario that scaled back reliance on these

[65] https://theicct.org/publication/fuels-us-eu-cost-ekerosene-mar22/

pathways were penalized for the lower GHG reductions attributable to these safeguards. However, we recommend that CARB instead pair these safeguards with expanded credit generation opportunities from ZEVs in order to complement CARB's existing strategies on ZEV deployment and equity while also maintaining its goals of more ambitious LCFS targets.

Currently, the LCFS greatly limits credit generation from fixed guideway public transit systems by limiting the energy-economy ratio multiplier of 4.6x to track lengths that were constructed after 2011. Despite these' systems high energy efficiency, potential to displace vehicle use and local air pollution, and contribution to local communities, their role in the LCFS to date has been minimal. For example, the BART system plays a crucial role in electric mobility in the Bay Area, but approximately 90% of its system predates 2011.[66] Extrapolating this under-crediting to the fixed guideway pathway as a whole, we find that there is substantial potential for credit generation to support public transit in California by applying the EER to all fixed guideway systems regardless of construction date. In July 2023 CATS modeling, we calculate approximately 6.2 Mtonnes of LCFS credits from fixed guideway systems would be generated from 2024-2045. Assuming a similar 90% relationship as in the BART system, applying the EER uniformly to all fixed guideway systems would increase the total credits over that time period to 26.3 Mtonnes—approximately 75% of the credits generated by virgin vegetable oils over that same time period. These credits could enable a virtuous cycle, enabling further capacity improvements for transit agencies and increasing ridership while displacing automobile use. Furthermore, these credits would allow CARB to set ambitious targets while implementing safeguards such as capping lipid-based fuels.

To help achieve California's long-term goals of electrification, using the LCFS to support the build-out of light and heavy-duty charging infrastructure is another opportunity to create a virtuous cycle. Lack of charging infrastructure remains a substantial barrier to EV adoption, particularly for low-income drivers or those living in multi-family housing.[67] There remain substantial further needs for charging infrastructure in California. For example, we estimate that Los Angeles will need more than 3,000 public fast charging stations by 2030 and San Francisco would require approximately 350. The proposed phasing down of light-duty fast charging infrastructure credits to 0.5% of the previous year's deficits in the proposal occurs too soon.[68] Therefore, we propose maintaining the size of the LDV FCI infrastructure credits at 2.5% of previous year's deficits.

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[66] Bay Area Regional Transit, 2023. *Letter to Cheryl Laskowski. RE: Potential Updates to the Low Carbon Fuel Standard Program*

[67] https://theicct.org/publication/quantifying-the-electric-vehicle-charging-infrastructure-gap-across-u-s-markets/; https://theicct.org/publication/when-might-lower-income-drivers-benefit-from-electric-vehicles-quantifying-the-economic-equity-implications-of-electric-vehicle-adoption/

[68] https://theicct.org/publication/los-angeles-electric-vehicle-charging-infrastructure-needs-and-implications-for-zero-emission-area-planning/ and https://theicct.org/wp-content/uploads/2021/06/SF-EV-charging-infra-oct2020.pdf