October 24, 2022

COMMUNITIES FOR A BETTER ENVIRONMENT
established 1978

California Air Resources Board ("CARB")
1001 "I" Street
Sacramento, CA 95814
SUBMITTED VIA CARB WEB PORTAL

Re: CBE comments on the Draft Recirculated Environmental Assessment (REA) for the 2022 Scoping Plan, focusing on Oil Refineries and related issues

Dear CARB Staff Members,

Communities for a Better Environment (CBE) is an Environmental Justice (EJ) organization, representing East Oakland, Wilmington, Richmond, Southeast Los Angeles, and surrounding communities, heavily impacted by fossil fuel pollution from mobile sources, oil refineries and drilling operations, power plants, and many others. CBE is a member of the California Environmental Justice Alliance (CEJA). We made extensive comments through the two CEJA letters submitted to CARB on the first draft Scoping Plan (May 10, 2022 draft)[1] which are still relevant. We incorporate these by reference, except where otherwise specified. We have additional comments below, and our CEJA partners are separately submitting further important comments on the REA. We appreciate that CARB recirculated the environmental assessment as a new draft to address new information and correct errors.

We are in the unusual position of having the new Sept. 9th REA[2] without the accompanying new Scoping Plan and modeling, so it is impossible to fully evaluate the REA draft. We reserve the right to add comments on the REA after the new Scoping Plan and modeling are published. **We appreciate statements clarifying that the REA does not provide complete CEQA analysis now, and more will be needed when the plan is implemented.** This is an important reminder for later project proponents that full CEQA analysis will be necessary. CARB states that best efforts were made to address impacts that can't be fully identified now due to uncertainties.[3] **However, it is important not to rely on future CEQA analysis for individual projects as a cure-all for gaps in environmental review.** The new Scoping Plan sets in motion and defines what types of projects will be proposed in the future, and the REA must adequately evaluate impacts and alternatives which could eliminate impacts. We understand the difficulties of assessing fast moving and complex energy changes over decades, but many impacts can be reasonably projected now, and prevented.

[1] Available through CARB's 2022 draft Scoping Plan web portal under three separate documents (662, 668, and 670) submitted by Chelsea Tu for CEJA -- CEJA Draft Scoping Plan Cross-Sector Comments, June 24, 2022

[2] Sept. 9, 2022, available at CARB web page: Draft 2022 Scoping Plan Update - Recirculated Draft Environmental Analysis

[3] For examples the REA states: *"If specific actions included in this Recirculated Draft EA are proposed by a public agency, further CEQA review of the individual projects would be undertaken as necessary."* (p. 8) Further: *"As described below, while CARB has made best efforts to analyze potential environmental impacts associated with these measures and recommendations, it is not possible to do so in greater detail given the statewide and programmatic nature of these measures, and the lack of available detail in how they may be implemented."* p. 11

We disagree with the characterization of the Scoping Plan as largely advisory[4] – many pieces are part of CARB's responsibilities and under its authority: CARB has the authority and responsibility to drastically cut Greenhouse Gases (GHGs), associated smog precursors, and toxic pollution. It also has an amazing opportunity to plan the phaseout of fossil fuels, not only to prevent climate collapse, but to finally eliminate the largest sources of the smog and toxics health crisis plaguing California for the last 80 years. This would also remove the largest sources of toxics poisoning Black, Latinx, Asian, and Indigenous and other communities which endure environmental racism and disproportionate impacts.

Specific inadequacies are summarized as follows, with more detail later:

- **Importantly, the Project Description is not up to date – it does not yet incorporate clear direction to <u>begin a planning process for a long-term oil refinery phaseout</u>, made by CARB's Governing Boardmembers and recommended by the Environmental Justice Advisory Committee (EJAC)** during the Sept. 1st 2022 hearing, detailed below. (This direction was also given by the Governing Board in its June hearing.) The Project Description incorporates some updates (e.g. substantial offshore wind, directed by Governor Newsom)[5] but left out the refinery phaseout planning, perhaps because of the short time between the Sept. 1st Board hearing discussion, and the Sept. 9th REA publication. We look forward to this addition in the fully updated Scoping Plan and correction of the REA and updated modeling.

- **The Project Description for oil refineries is also outdated in its assumption that most refinery operations could have Carbon Capture and Sequestration (CCS) implemented by 2030 –** this has already been discarded by CARB staff after it was documented as infeasible for refineries (see below), and also since it cannot be considered until after federal pipeline safety regulations are updated for concentrated CO2 transport from oil refineries to the Central Valley.[6]

- **We appreciate that the evaluation of CCS has been updated to add previously missing information regarding CO2 pipeline hazards, but it is still incomplete** – it does not adequately evaluate and provide feasible mitigation for extremely harmful impacts from overcrowding oil refineries, and transporting and sequestration of CO2.

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[4] REA: *"Note that despite the inclusion of these items, the 2022 Scoping Plan continues to remain largely advisory in nature, as CARB does not directly regulate many of the sectors described above, and therefore these measures remain at the discretion of other agencies."* p. 11

[5] The REA states that the Project Description has been revised: *"After the end of the Draft EA public review period, CARB identified revisions to certain aspects of the proposal that merit revisions to the project description. The changes are provided in Chapter 2, "Project Description," below. In addition, in response to public comment, the public safety evaluation has been reassessed and expanded for carbon dioxide pipelines associated with potential atmospheric mechanical carbon dioxide removal projects and carbon capture and storage projects."* REA at p. 1

[6] "For example, SB 905 (Caballero, 2021-2022 legislative session, enrolled by the legislature but not signed by the Governor at the time of writing) does not allow for the transport of concentrated carbon dioxide via pipelines until a federal CO2 pipeline safety rulemaking is completed. It is unknown at this time when that rulemaking will conclude." REA, p. 16. Note this was subsequently signed by Governor Newsom, Sep. 16, 2022: S905 California: Carbon sequestration: Carbon Capture, Removal, Utilization, and Storage Program, <u>Trackbill.com</u>

- **Analysis of the production, transport, storage, use, and cost of hydrogen requires much more robust analysis to include readily available information on the many major impacts.** These are an important piece of Scoping Plan development and environmental assessment, to prevent new significant impacts and bad policy. Some decisionmakers are grasping at hydrogen as an easy fuel switch from fossil fuels, but this must be corrected with clear and specific analysis of impacts and cleanest energy options.

- **By far, most hydrogen is currently made using fossil fuels in oil refinery-associated processes (over 2 million kg/day) making it the most likely source of hydrogen for many years.**[7] There is heavy oil industry pressure to continue and expand this production, with a blind eye to impacts, while adding CCS to hydrogen plants to justify continued fossil hydrogen plant operation. But refinery CCS cannot eliminate most of the impacts from refinery hydrogen production, natural gas feedstock extraction, and transport and storage of hydrogen and natural gas associated with it. Furthermore, hydrogen production is a fraction of overall refinery operations, but used to justify continued existence of the vastly larger, other parts of refinery operations for the foreseeable future -- beyond 2050.

- **Even green hydrogen generated using renewable energy has environmental impacts, requiring substantial water resources, and very high electricity use to produce hydrogen (perhaps prohibitively high), in addition to transport and storage impacts.** Combustion of hydrogen from any source causes major NOx emissions (though hydrogen fuel cells do not emit NOx, only water). Hydrogen consideration should be limited to applications where no cleaner alternative is available, before adoption of the Scoping Plan energy portfolio. A source-by-source evaluation of hard to decarbonize sectors should be made including long-haul trucking, aviation, ocean-going vessels, other transportation, isolated geographic areas (islands), certain intensive industrial operations (not including oil refining, which cannot be decarbonized), to identify cleanest alternatives available, and lowest impact clean energy alternatives.

I. Petroleum Refining in the Project Description must include beginning planning refinery phasedown, and correct errors regarding availability of CCS

For Oil Refineries, the Sept. 9th draft REA Project Description table of actions (p. 17) is unchanged from the original May 10, 2022 EA Project Description (p. 15). The REA contains two errors requiring updating: A) the Governing Board and EJAC directed staff to add actions to the Scoping Plan to begin planning to manage a long-term phasedown of Oil Refining and Oil Drilling in California, and B) CCS is known to be unavailable for the majority of refinery operations by 2030. The REA still includes the inaccurate and outdated descriptions:

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[7] Natural gas produced from oil and gas drilling operations usually provides both the energy driving the process and the feedstock materials in Steam Methane Reforming (SMR), which is currently the main process used to produce hydrogen in high volume. Methane (CH_4) in the natural gas is reformed to free hydrogen atoms, also emitting large volumes of CO_2 and other pollutants. We listed and quantified the hydrogen produced from a number of existing fossil-fuel producers of hydrogen in the state, later in this comment.

Table 2-1: Actions for the Proposed Scenario: AB 32 GHG Inventory Sectors[8]

Petroleum Refining	CCS on majority of operations by 2030 Production reduced in line with petroleum demand

A) The Refinery description in Table 2-1 should have been amended to include beginning phasedown planning as instructed by the Board and EJAC

During the Sept. 1, 2022 joint meeting of CARB Governing Board (and Environmental Justice Advisory Committee) directed staff to add the beginning of planning on Oil Refinery and Oil Extraction phaseout. Here are a few of the statements made by CARB Governing Boardmembers and EJAC members[9] (many others were made):

Sharifa Taylor, EJAC Co-Chair, beginning 1:10:26: **"We want to move actually into our recommendations for the refinery phaseout, or just transition** . . . By 2024 . . . **CalEPA should lead the adoption of an interagency plan to manage the decline of California oil refinery production** of gasoline, diesel, and other fossil fuels, as it reflects California's climate laws and zero emission transportation policies by 2045."

Kiran Chawla, JD/PhD Candidate, EJAC, proxy for Connie Cho, EJAC, 45:57: "**CARB should develop and complete a petroleum transition plan by 2024** that lays out a vision for production phase out of petroleum refining by 2045, including the development of interim targets."

Chair Randolph, CARB Governing Board beginning 1:22:50: "**We would like some paragraphs added to the Scoping Plan calling on the Governor to convene an interagency working group to assess the transition of not just refineries, but also I think it needs to include extraction**. . . "

CARB Boardmember Kracov, beginning1:18:47: "If you don't pay attention to where you're going, you're probably gonna end up somewhere else. **So on this issue, we discussed last time, sending a strong signal - language to signal the need for candid, prudent deliberation, and planning. Maybe multi-agency, on the petroleum phase out** to disclose the constraints and tackle all these tough questions."

CARB Boardmember Dr. Balmes, 1:32:09: "**I totally support a phaseout plan**"

CARB Boardmember Hector De la Torre, 1:21:51: "On this issue of oil and gas um back in June I spoke up on this and I still believe it to this day. Since then I've been telling people that I know that this is the direction that we need to go, from other agencies, electeds, etc. I believed it then, I believe it now.

Many other statements, recommendations, and directions to staff were made directing phaseout, and also asking for evaluation and care for worker training and community transitions and impacts, rebate incentives for clean electric vehicles, and special attention to different transportation and electricity charging needs in rural areas.

[8] REA excerpt p. 17

[9] Video recording available at: https://cal-span.org/meeting/carb_20220901/

In addition, Sharifa Taylor, EJAC Co-Chair referenced the PERI[10] report as a model, labor-supported plan regarding how oil industry phasedown can could be carried out with worker training support. Because a full transcript is not clearly available online, it was not easy to provide a set of all the quotes here, but the full conversation is available at the footnoted link. Boardmember Takvorian added comments supporting such planning and the need for timelines and details, and Boardmember Hurt added comments of general support, as did others.

Consequently, the Project Description Table 2-1 Actions must be updated, for example as follows:

Table 2-1: Actions for the Proposed Scenario: AB 32 GHG Inventory Sectors[11]: example correction

Petroleum Refining	~~CCS on majority of operations by 2030~~ <u>CCS consideration is delayed until after federal pipeline safety regulation updates for concentrated CO2 transport</u> ~~Production reduced in line with petroleum demand~~ <u>By 2024, develop near and long-term plans through an interagency taskforce to manage the decline of oil refining and oil extraction (fossil fuel supply phasedown), in line with California's climate and zero emission transportation goals (for reduced fossil fuel demand by 2045).</u>

Additional detail on planning workforce training and community transition need to be developed for the new Scoping Plan update, and consistently addressed in the REA.

B) "CCS on majority of operations by 2030" for oil refineries has already been found by CARB and others as not achievable; DOE's expert and spokesperson agrees

The original EA modeling assumed widespread refinery CCS could by implemented starting immediately, ramping up to capturing 13 million tonnes of CO2 by 2030 at oil refineries.[12] However, CARB later reviewed these assumptions and concluded that CCS is currently non-existent at oil refineries in California, and that the modeling assumptions for large quantities of CO2 captured could

[10] A PROGRAM FOR ECONOMIC RECOVERY AND CLEAN ENERGY TRANSITION IN CALIFORNIA, Robert Pollin, Jeannette Wicks-Lim, Shouvik Chakraborty, Caitlin Kline, and Gregor Semieniuk, Dept. of Economics and Political Economy Research Institute (PERI) University of Massachusetts-Amherst, June 2021, at: https://peri.umass.edu/images/CA-CleanEnergy-6-8-21.pdf

[11] REA excerpt p. 17

[12] For example, see Attachment A, May 13, 2022, CBE, ***FACT CHECK****: California's 2022 Draft Scoping Plan for Oil Refineries, Released Data Show CARB Relies on Unfounded Assumptions for Carbon Capture in the Refinery Sector, Making Results Invalid*

not be met by 2030.[13] Outside California, there are only a small handful of refinery-related CCS project, with many having failed to achieve their own goals to reduce emissions.[14]

CCS for oil refineries has been documented to require specialized design due to size, age, and severe space constraints at refineries, limiting CCS applicability to a small number of CO2-emitting combustion units (and not practical for the "majority" of operations).[15] The timeline for refinery CCS implementation would require customized engineering design, environmental review, permitting, and construction, and would not be achievable even in limited operations for oil refineries until closer to the end of the decade. We submitted extensive comments through CEJA documenting industry and regulatory statements of the severe refinery space constraints and major hazards reducing maintenance access and increasing accidents. These comments are still relevant and incorporated by reference. If CARB attempted to implement widespread CCS requirements in refineries on the majority of operations by 2030, this would increase the already high dangers of explosions, spills, and fires at refineries.

We supplement our previous comments with additional information below.

Application of CCS to the "Majority of operations" was originally given more meaning in the original Scoping Plan, where the original modeling provided the <u>volume of CO2</u> in metric tonnes each year expected captured. That document assumed large volumes of refinery emissions could be captured through CCS (13 million tonnes/year by 2030). This volume definition was shown infeasible.

But now, without availability of the new modeling (not expected until November), there is no public gauge at all defining the "majority of operations" (either in quantities expected captured), nor in terms of defining which parts of the refinery would be equipped with CCS. [16] This leaves a big gap in Project Description, and environmental impact analysis.

Definition of "majority" is necessary, to identify not only volumes CARB is projecting to be captured, but also which refinery processes would be possible candidates, what portion of emissions might be capturable, and how large a portion of refinery real-estate would be needed. Evidence shows that only a portion of oil refinery combustion emissions can be captured and that large portions of refinery property are not available to add more equipment if safety isn't to be further compromised. (Pilot projects to develop "compact" CCS modules footnoted by CARB in the May 10th Scoping Plan,

[13] In an April 2022 public workshop CARB agreed that these assumptions were incorrect. In response to such comments, CARB also agreed in the subsequently published May 2022 draft Scoping Plan that "[w]hile the modeling included CCS as being available in the first half of this decade, implementation barriers now indicate that is unlikely, and those emissions will be emitted into the atmosphere. For the Final 2022 Scoping Plan, the modeling will reflect updated assumptions for the earliest deployment of CCS for any sector in California." Draft Scoping Plan at 68. Moreover, during the May 23, 2022 meeting of the Environmental Justice Advisory Committee (EJAC), CARB staff acknowledged that they now assume refinery CCS will be unavailable until "later this decade."

[14] For example, see previously cited CEJA Scoping Plan comment of June 24, 2022, at p. 19, available at https://www.arb.ca.gov/lists/com-attach/4459-scopingplan2022-UDMAY1Y9V2VQCQBk.pdf

[15] CEJA, *Id,* pp. 20-27

[16] This is an example of the problem with publishing an environmental assessment before publishing the project or program document itself (in this case – the updated Scoping Plan and updated modeling). We have never seen an environmental assessment published under CEQA *before* the full project was defined.

are only currently designed for smaller volume capture, as we documented in our previous CEJA comments.[17])

Not only is it already established that the majority of refinery operations cannot have CCS operable by 2030, but the Department of Energy (DOE) representative went further in public comments. The keynote speaker Dr. Jennifer Wilcox, DOE, Office of Fossil Energy and Carbon Management, stated at the CCS Symposium Sept. 29th, 2022 in Stockton: **"Carbon capture is not the right tool for refineries**." We agree. CARB staff helped convene and were present at this symposium and have access to notes and a recording of this event, which we incorporate by reference.

C) Refinery Title V permits provide detail on refinery fossil fuel combustion units, encompassing far more than Hydrogen Production & FCCs as largest CO2 sources

In order to further illustrate the large numbers of operations where CCS in refineries would need to be applied if CARB expected to cover the majority of large refinery combustion sources, CBE made the effort to compile from publicly available Title V permits, a list of refinery combustion units and their capacity (firing rate for burning natural gas or refinery gas in millions of BTUs[18] per hour, resulting in CO2 and other emissions). We also previously provided other lists of the large numbers of combustion units at South Coast refineries in our previous CEJA comments documented in NOx Regulation 1109.1, which are still relevant (though not as detailed as the table below for an individual refinery, regarding specific refinery combustion units). Unfortunately, this issue is still receiving a trivial level of evaluation in the REA.

The Title V permits establish the large number of refinery fossil fuel combustion processes which would need to be controlled if CARB meant to include CCS on "the majority" of refinery operations by 2030 in the Scoping Plan.

CARB has already found the notion of applying CCS to the majority of operations as untenable, as previously cited. And in fact, CARB only briefly identified three specific refinery operations in the original Scoping Plan: 1) refinery Hydrogen Plants (Steam Methane Reformers or SMR), 2) refinery Electricity production (combined heat and power), and 3) [Fluid] Catalytic Cracking units (FCCs), stating in the May 10, 2022 Scoping Plan: *"Refineries can have a variety of point sources that emit CO2, such as steam methane reformers for producing hydrogen, combined heat and power units, and catalytic crackers."* (p. 68)

We show at least *ten* major refining activities would need to be covered if the majority of CO2 emissions were to be addressed. Each of these ten categories have multiple separate combustion units, requiring separate controls. It is not feasible to cover all these refinery operations with CCS, underscoring the lack of realism in having a general and undefined goal of covering "the majority of operations" at refineries. It appears that CARB has not actually evaluated the scope of refinery operations in this regard, but instead relied on hopeful and generalized thinking, but technically flawed concepts.

[17] CEJA, *Id,* pp. 27-29
[18] British Thermal Units

As a real-world example, we extracted Title V permitting information for the Tesoro / Marathon Carson refinery, which has about 36 major boilers, heaters, furnaces, and turbines listed in its most recent Title V permit. To address 90% of the emissions from these (a percentage repeatedly stated by CARB as achievable for CCS capture) would require equipping the largest 19 out of the 36 below, encompassing ten different major refinery processes: 1) Electricity Generation, 2) Hydrogen Generation, 3) Crude Oil Distillation, 4) Vacuum Distillation, 5) Catalytic Reforming, 6) Hydrocracking, 7) Fluid Catalytic Cracking, 8) Coking, 9) Steam Generation, and 10) Hydrotreating.

Thus, at a refinery like Tesoro Carson – CCS would need to be applied separately to each of 19 major combustion units if CARB wished to assume it could capture CO2 resulting from 90% of the fuel combusted in the list of boilers and heaters below.[19]

The Tesoro / Marathon Los Angeles Refinery (Carson) from largest to smallest[20]

Size (in Million BTUs of fuel combusted per hour, or MMBTU/hr)	Refinery System/Process (from Title V permit)	Equipment description (from Title V permit)
985	Electricity Generation	Gas Turbine
650	Hydrogen Production	Heater, Primary Reformer
550	Crude Dist. Unit	Heater, No. 1
427	Hydrogen Production	Heater RW0054
360	Vacuum Distill. Unit	Heater No. 51
310	Catalytic Reforming	Heater No. 2 Reformer #015
255	Cat Reform. Unit	Heater No. 1 Reformer 014
173	Hydrocracking	Heater, Reboiler No. 017, Hydrocracker Fractionator
171	Catalytic Reforming	Heater, No. 3 Reformer, No. 016
165	Fluid Catalytic Cracking	Heater RPV 2319, Regenerator Startup Air Heater
150	Crude Dist. Unit Heaters	System 4- Heater, No. 21, No. 2 Crude Oil Distillation
130	Coking & Resid. Conditioning	Heater, No. 1 Delayed Coker Unit (West)
130	Coking & Resid. Conditioning	Heater, No. 1 Delayed Coker Unit (East)
130	Coking & Resid. Conditioning	Heater, No. 2 Delayed Coker Unit
130	Crude Oil Distillation	Heater, No. 4 Crude Oil Distillation Charge
120	Crude Oil Distillation / Vacuum	Heater, No. 52 Vacuum Unit
100	Crude Oil Distillation	Heater No. 22, No. 2 Crude Oil Distillation
89	Fluid Cat Cracking	Heater, Fluid Cat Cracking Feed

[19] We used fuel combustion capacity as a surrogate for CO2 emissions – the more fuel a unit can combust, the more CO2 emitted. These units generally operate continuously. CARB can readily fill in this chart to provide actual CO2 emitted for each source, or we could calculate using a standard emission factor for each, but fuel combustion percent is a reasonable approximation of percent CO2 emissions.

[20] Tesoro Refining and Marketing, Facility ID 174655 (aka Marathon), 6/24/22 Title V Permit, available through SCAQMD "FIND" query, at https://www.aqmd.gov/nav/FIND . We have also attached more detailed spreadsheets compiling the list above, providing the Application #, the individual equipment Unit #, and the page number in the Title V permit, as well as the Title V permit itself.

82	Hydrotreating	Heater No. 018, Mid-barrel Stabilizer Reboiler
80	Hydrotreating	Heater FCC HDS (HydroDesulfurization) Unit)
52	Catalytic Reforming	Heater, No. 1 Reformer Desulfurizer
52	Hydrotreating	Heater No. 018, Mid-barrel Stabilizer Reboiler
39	Catalytic Reforming	Heater No. 2A, Process Reformer
39	Cat Reforming	Heater No. 2, Desulfurizer No. 2B
39	Hydrocracking	Heater, No. R1
39	Hydrocracking	Heater No. R2 Recycle Gas
39	Hydrocracking	Heater No. R4
39	Hydrocracking	Heater No. R3 Recycle Gas
24	Hydrotreating	Heater, Jet Treater R-1
22	Hydrotreating	Heater Light Gasoline Hydrogenation Feed
12.5	Hydrotreating	Heater, RW 0053, Naphtha HDS Reactor
11	Hydrotreating	Heater, Jet Treater R-3
10	Hydrotreating	Heater, Jet Treater Stabilizer Reboiler
4.9	Fluid Catalytic Cracking	Propylene Tetramer Reboiler
3.9	Crude Oil Distillation	Slop Oil Rerun Unit Heaters

The total fuel combustion capacity above is in 5,614 million BTUs per *hour*. (See attached pdf of spreadsheet (Attachment A) – the live spreadsheet is available on request.) Using the CO2 Emission Factor of 53.06 kg/MMBTU for combustion of natural gas results which was used by Tesoro during their 2017 environmental permitting,[21] results in CO2 emissions of about 1.3 million metric tonnes/year (MMt/yr).[22] Capturing 90% of the combustion capacity (shaded in blue above) would capture about 1.2MMt/yr.[23] This emission factor may be a major underestimation of actual combustion emissions but regardless illustrates the large percentage of processes which would need to be controlled to reach 90%.

We could similarly compile the Tesoro Wilmington, and other California refinery combustion units from their publicly available Title V permits. Such detail in permits only adds to the already overwhelming evidence that complex refineries cannot readily include CCS on the majority of operations by 2030.

A similar distribution of the largest CO2-generating combustion sources operating across multiple refinery operations (representing "the majority of operations") would be expected at refineries statewide. These units combust mainly Refinery Gas and Natural Gas, and also cause large emissions of Nitrogen Oxides, Particulate Matter, and other pollutants harmful to local health, in addition causing regional ozone formation.

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[21] Tesoro Los Angeles Refinery Integration and Compliance Project, Appendix A: Summary of Emissions, Table A-2: Carson and Wilmington New and Modified Heater Emissions (Potential to Emit), Emissions Factors, Appendix B-3, p. B-347.

[22] 5,614 MMBTU/hr X (53.06 kg CO2 /MMBTU of Natural Gas combusted, per 40 CFR Default) ÷ (1000kg/metric tonne) X (8760 hrs/year) = 2.6 million metric tonnes CO2 per year (MMt/yr).

[23] >90% of 2.6 MMt/year = ~2.4 MMt/year

The REA must be corrected to remove the goal of CCS on a "majority of refinery operations" by 2030 for all of the above reasons. If not, CARB would need to provide an analysis showing the feasibility and potential impacts of adding CCS to each of these known process units above, and consider alternatives to each of these. Further, CCS at refineries must not even be considered by CARB before major improvements in federal CO2 pipeline standards.

D) Refineries cause many other harms, such as major cancer-causing benzene emissions from Storage Tanks and leaking fugitive sources (valves and seals); CCS would not cover any of these, leaving communities with continued toxic emissions

We could similarly performing a time-consuming list the even larger number of refinery storage tanks from Title V permits and other sources at refineries – these are even more numerous than heaters and boilers. It is important for CARB and decisionmakers to realize that such petroleum storage tanks (which emit cancer-causing and smog-forming chemicals, even after decades of regulations to tighten emissions) are entirely uncontrolled by CCS (which is for the purpose of capturing CO2 from combustion).

Consequently, generalized ideas that CCS could somehow address the harms to EJ communities is entirely unrealistic and uninformed regarding the number of different operations at refineries. It is important to recognize that these operations are inherently polluting and must be phased down, not only to protect the climate, but to protect health of nearby neighbors (as well as workers) over time.

II. CCS - CO2 Pipeline and other CCS hazards are still inadequately assessed

Especially since the Scoping Plan still proposes CCS on the majority of refinery operations, and has not yet seriously evaluated the impacts on complex, overcrowded refinery operations, weighed the seriousness of CO2 pipeline impacts, the leaking potential in the Central Valley, nor incorporated severe health impact information presented at the late September CCS Symposium in Stockton (where CARB took part with other regulators and EJ organizations), we are looking forward to supplementing our comments on this issue after the full Scoping Plan and modeling are updated, and hopefully the REA is as well.

III. Hydrogen source impacts are underestimated, with inattention to existing conditions and most likely outcomes

A. Key Background Issues and Impacts

It is understandable that many officials have pinned hopes on a generalized idea of hydrogen as an easy gas or liquid replacement for fossil fuels, since combustion of hydrogen does not emit CO2. It is also a relatively intensive and storable fuel (as compared to intermittent wind and solar).

But focusing only on hydrogen's benefits ignores major, predictable impacts, which are inevitable unless included in robust planning and environmental analysis. California has previously failed to analyze known pitfalls during policy cross-roads – kicking the can down the road.

It is now crucial (and required by CEQA) that a full evaluation of California's projected energy portfolio be based on the actual information and data regarding known pitfalls, including evaluating hydrogen impacts. We are out of time to develop good climate energy policy, and CARB may not assume that a project-by-project analysis down the road will cure all ills.

Based on impacts, the REA must evaluate limitations of hydrogen use, and more importantly, where straightforward electrification alternatives avoid impacts, to protect public health and the climate. The following factors need to be much more clearly evaluated:

- **Combustion of hydrogen creates large volumes of NOx** (even more than combustion of natural gas[24])**, harming health,** due to presence of nitrogen in the atmosphere. (Hydrogen use in fuel cells on the other hand, do not create NOx). EJ communities need to eliminate such health-harming sources.
- **The existing infrastructure in California to produce hydrogen is large and polluting, making it very likely dirty hydrogen use will expand.** CCS can only partially eliminate some of the impacts of fossil-fueled hydrogen production.
- **Even green hydrogen (produced from water using renewable energy) has major impacts which must be carefully considered,** including requirements for large amounts of water, and extreme amounts of renewable energy to power electrolysis (which is a relatively inefficient process[25]).
- **Hydrogen is an indirect but potent GHG, and is flammable and explosive.[26] Leaks in hydrogen pipelines create new impacts and hazards.** Hydrogen leaks contribute to climate change - by reacting with radicals in the atmosphere, hydrogen increases levels of

[24] The Chemical Engineer, Hydrogen, The Burning Question, *"Disadvantages include: • the higher flame speed increases the flame temperature locally, which can generate high levels of NOx;"*

[25] GTM: A Wood Mackenzie Business, Energy, *So, What Exactly Is Green Hydrogen?*, *["The business case for* ***green hydrogen requires very large amounts of cheap renewable electricity because a fair amount is lost in electrolysis.*** *Electrolyzer efficiencies range from around 60 percent to 80 percent, according to Shell. The efficiency challenge is exacerbated by the fact that many applications may require green hydrogen to power a fuel cell, leading to further losses."]*

[26] US OSHA, Green Job Hazards, Hydrogen Fuel Cells: Fire and Explosion *["Hydrogen used in the fuel cells is a very flammable gas and can cause fires and explosions if it is not handled properly. Hydrogen is a colorless, odorless, and tasteless gas. Natural gas and propane are also odorless, but a sulfur-containing (Mercaptan) odorant is added to these gases so that a leak can be detected. At present, it is hard to tell if there is a hydrogen leak because it has no odor to it. Hydrogen is a very light gas.* ***There are no known odorants that can be added to hydrogen that are light enough to diffuse at the same rate as hydrogen.*** *In other words, by the time a worker smells an odorant, the hydrogen concentrations might have already exceeded its lower flammability limit."]*

the potent GHG methane.[27] **Blending of hydrogen into natural gas pipelines can embrittle them.[28]**

CBE and CEJA have previously proposed that hydrogen be *considered* during environmental evaluations, only for limited use in truly hard to decarbonize sectors for which there is not a better alternative, given serious potential environmental impacts. CARB has at times described its goals for hydrogen similarly.

However, oil refining (which CARB once referenced as “hard to decarbonize” should never be lumped into this category – refineries are actually impossible to decarbonize – they inherently process carbon in the form of crude oil (or limited amounts of biofuels), to make carbon fuels (gasoline, diesel, etc.). These result in toxic and GHG emissions that can never be entirely controlled. They are inherently dangerous, operating under high temperatures and pressures, and regularly explode. As inherent fossil fuel polluters – they need to be phased down over time in favor of inherently safer, zero emission energy sources to protect surrounding communities and the climate.

It will be important for the Scoping Plan energy portfolio development and environmental analysis to carefully evaluate each hard to decarbonize sector individually, such as long-haul trucking, ocean-going vessels, aviation, and certain intensive industrial applications (perhaps the steel industry).[29] The REA must evaluate each of the impacts described above, and address these within production, transport, and use of hydrogen for each sector, **and evaluate whether safer alternatives (such as electrification) are available, as they frequently appear to be.**

B. California’s major production of hydrogen from fossil fuels for refinery use, and non-existent green production at present, gives dirty hydrogen the economic and logistical advantage for some time in the future

Existing large volumes of fossil-fuel produced hydrogen (called grey hydrogen) and lack of green hydrogen (made from renewable energy), make it predictable that most hydrogen production in

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[27] Warwick et al, University of Cambridge, *Atmospheric implications of increased Hydrogen use,* April 2022, Executive Summary, *[“. . . any leakage of hydrogen will affect atmospheric composition (with implications for air quality) and have an indirect warming effect on climate, partially offsetting some of the climate benefits of the reduction in carbon dioxide. . . . Leakage of hydrogen into the atmosphere will decrease the tropospheric concentration of hydroxyl radicals (OH), the major tropospheric oxidant, and* ***thereby increase the atmospheric lifetime of methane and its impact on climate****.”]*

[28] Hafsi et al, *Hydrogen embrittlement of steel pipelines during transients,* https://www.sciencedirect.com/science/article/pii/S2452321618302683

[29] For example, in the steel industry, hydrogen is being explored as a potential reducing agent (removing oxygen from feedstock but resulting in large CO2 emissions) to replace coal. This is not yet a readily available alternative. This is an example of CO2 emissions as an inherent part of the chemical reactions of an industrial process (not simply as an energy source for heat). Owais Ali, Jul 27 2022, AZO Greentech, Editorial Feature, Green Hydrogen for Steel Production, *High Carbon Footprint of Steel Production* describes a hydrogen reducing agent alternative. *[“Blast furnaces of steel industries utilize carbon in a chemical reaction that transforms carbon and iron oxide into carbon dioxide and iron. To decarbonize steel production, carbon and carbon dioxide must be replaced by a gas that produces little or no carbon emissions. Green hydrogen can replace carbon and fully decarbonize these processes. However, green* H_2 *is currently only being generated in small amounts; therefore, it needs to be optimized for industrial-scale production before it can be used to make steel.”]* https://www.azocleantech.com/article.aspx?ArticleID=1606

California for at least a decade will be grey. Oil refineries and their associated third-party hydrogen producers have an economic advantage over green hydrogen producers: refinery-related hydrogen plants are already built. Green hydrogen plants will require design, siting, construction, high operating expenses, access to renewable electricity, and environmental approvals.

The REA does not define the sources of the hydrogen which it projects for use, and generally fails to distinguish between grey and green hydrogen in evaluating impacts. Most hydrogen inside (and outside) California is made using fossil fuels, for oil refineries using Steam Methane Reforming.[30] These plants are known by CARB, which should provide an up-to-date listing. We provide a partial list below.

Hydrogen plants in California are owned by 1) refineries and 2) third parties, usually operated next to or even on refinery property. The trend for a decade has been for increasing production by third parties partnering with refineries (basically captive industries).[31] The *Renewable Hydrogen Roadmap*[32] provided a partial list of third parties producing hydrogen in California in 2016, which shows the domination of end-use by oil refineries:

Renewable Hydrogen Roadmap Figure 4. California Hydrogen Production (January 2016)

Producer	City	Technology	Capacity (kg/day)	Industry
Air Products	Sacramento	SMR	5,542	Multiple
Praxair	Ontario	SMR	20,483	Multiple
Air Liquide	El Segundo	SMR	207,240	Oil Refining
Air Liquide	Rodeo	SMR	289,172	Oil Refining
Air Products	Carson	SMR	240,976	Oil Refining
Air Products	Martinez	SMR	212,059	Oil Refining
Air Products	Martinez	SMR	84,342	Oil Refining
Air Products	Sacramento	SMR	Unknown	Food
Air Products	Wilmington	RFG SMR**	385,562	Oil Refining
Praxair	Ontario	SMR	28,917	Multiple
Praxair	Richmond	SMR	626,539	Oil Refining
Total[33]			2,100,832	
Total third party 2016 exclusive Refinery use			2,045,890	

** RFG SMR = Refinery Fuel Gas SMR – uses refinery gas byproducts, instead of natural gas

Additional California refinery hydrogen plants not listed above:

[30] Steam Methane Reforming or SMR, reforms CH4 (methane) provided by natural gas, into hydrogen, with large amounts of CO2 and other pollutants emitted.

[31] US EIA, Jan. 20, 2016, Hydrogen for refineries is increasingly provided by industrial suppliers

[32] Renewable Hydrogen Roadmap, EIN (Energy Independence Now), 2019, p. 13, ["A significant amount of hydrogen is produced in California to supply the oil refineries (over 2 million kg per day) while additional hydrogen is largely consumed by the food and metals industries. Figure 4 provides data on levels of hydrogen produced by IGCs [Industrial Gas Companies] to supply oil refineries."]

[33] Note the total provided by EIN only included third party hydrogen production.

- **In 2020 the PBF Torrance refinery sold five hydrogen plants to Air Products** (*"Torrance Refinery owner PBF Energy has sold five hydrogen plants, including two in Torrance"*),[34] adding to the above third-party capacity in Torrance and Martinez California, and Delaware City, Delaware, with a combined capacity of 300 million scf/day.[35]

- **The Chevron Richmond refinery also has two hydrogen plants with capacity of 181.1 scf/day**,[36] with plans to expand.

- **Partnerships of oil refineries and third-party operators is common, and described in a 2003 Chevron El Segundo Negative Declaration (ND) CEQA review for a new hydrogen plant**: *"The new Hydrogen Plant is being developed by Air Liquide America, LP for Chevron. Chevron will be the operator of the Hydrogen Plant with Air Liquide as the legal owner."*[37] The ND gave capacity at 90 million standard cu ft / day[38].

- **The Valero Benicia refinery operates two hydrogen plants** (unknown capacity) which incidentally were cited for secretly venting hydrogen and other pollutants for years.[39,40]

Other data sources are available:

The US Energy Information Administration (EIA) also provides data on total hydrogen production in California. The most recent pre-pandemic (2019) California hydrogen production in the US EIA data: 1,219 million cubic ft/day,[41] equivalent to about 2.88 million kg/day total for both refineries and third parties producing hydrogen for refineries in PADD 5.[42] 2016 data is also available from US EIA for easier comparison with the *Renewable Hydrogen Roadmap* data above.

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[34] Daily Breeze, Nick Green, March 31, 2020, *Torrance Refinery owner sells assets as coronavirus pandemic tanks gas demand* attached.

[35] Air Products, *Air Products Signs Agreements to Acquire Five Operating Hydrogen Plants for $530 Million and Long-Term Hydrogen Supply to PBF Energy* *["Air Products (NYSE: APD) today announced it has signed agreements with PBF Energy Inc. (NYSE: PBF) that include the $530 million purchase of five hydrogen steam methane reformer (SMR) hydrogen production plants and the long-term supply of hydrogen from those already operating plants to PBF refineries. The SMRs, with a combined nearly 300 million standard cubic feet per day of production capacity, are located in Torrance and Martinez, California and Delaware City, Delaware."]*

[36] Chevron Products Company, Richmond Refinery, *Greenhouse Gas Emission Reductions from the Hydrogen Plant Replacement at the Richmond Refinery,* March 2021, p. 6, https://ww2.arb.ca.gov/sites/default/files/2021-03/2021-0319-chevron-report.pdf

[37] Final Negative Declaration for: Chevron Products Company Refinery Proposed Hydrogen Plant Project, (El Segundo) July, 2003, p. 1-1

[38] *Id,* p. 1-6.

[39] https://www.kqed.org/news/11905065/first-i-had-heard-of-it-valeros-benicia-refinery-secretly-released-toxic-chemicals-for-years

[40] Valero Refining Company – Separate Statement, Stipulated Order of Abatement, Docket #3731, March 10, 2022, at https://www.baaqmd.gov/~/media/files/board-of-directors/hearing-board/agendas/2022-hb/statement-by-respondent-filed-031022-pdf.pdf?la=en&rev=1f4d469a92e0431881b86497fde4687c

[41] US EIA, Production Capacity at Operable Refineries, 2019.

[42] Hydrogen: 423.3 standard cu ft / kg. 1,219 million cu ft / 423.3 cu ft/kg = 2,879,754 kg http://www.uigi.com/h2_conv.html

Worldwide, there are few industrial-scale green hydrogen plants. It would be helpful if updated proceedings would include listings, so that CARB could assess hydrogen within the current real-world circumstances – where most hydrogen is fossil-fuel produced.

We appreciate the work of CARB producing the REA, but urge correction of the deficiencies identified above, and we look forward to the publication of the updated Scoping Plan consistent with these comments, as well as associated modeling.

California has a complex but great opportunity to stop smog and the majority of toxic emissions in the state, and stop California's huge contribution to planet-wide climate disaster. This can provide a model for other states. While difficult, this is technologically and economically feasible and necessary to protect public and environmental health. Thanks for your work.

Sincerely.

Alicia Rivera, CBE Wilmington Community Organizer

Connie Cho, CBE Staff Attorney

Julia May, CBE Senior Scientist

Also see Attachments A & B

Attachment A

FACT CHECK: California's 2022 Draft Scoping Plan for Oil Refineries

COMMUNITIES FOR A BETTER ENVIRONMENT established 1978

Released Data Show CARB Relies on Unfounded Assumptions for Carbon Capture in the Refinery Sector, Making Results Invalid

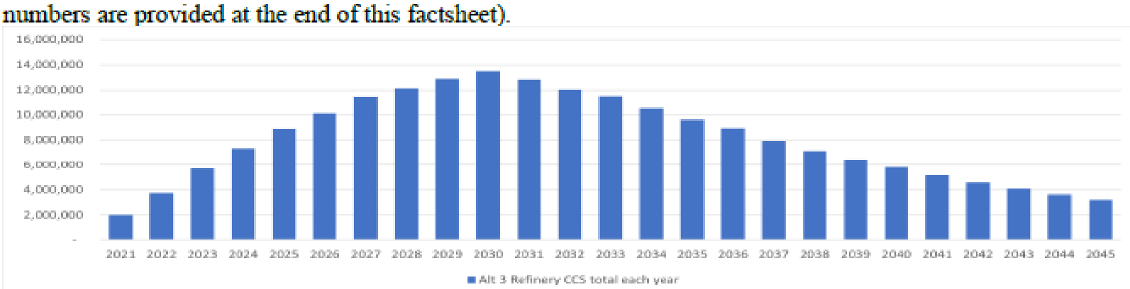
On Tuesday, May 10, 2022, CARB finally published the 2022 Scoping Plan modeling assumption spreadsheets. These key datasets underlying the foundational climate modeling for the Scoping Plan were surprisingly unavailable to support charted results in previous modeling results workshops. Now that detailed numbers are public, the nature of CARB's faulty input assumptions are clearer. These reflect forced policy decisions, not faults in the modeling program. The E3 modeling spreadsheets[1] provide year-by-year greenhouse gases assumed captured by carbon capture and sequestration (CCS) at oil refineries. These faulty assumptions invalidate the results of the refinery sector in the staff-preferred Alternative 3, the Proposed Scenario.

- As presented in the graph and citations below, **CARB modeling assumed CCS technology in refineries would need to <u>start capturing over 2 million metric tonnes</u> (MMT CO2e) at refineries, in <u>2021</u>.** Capture would ramp up to a **<u>peak of 13 million in 2030</u>** and continue capture through 2045.

But these carbon capture systems do not currently exist at any refinery in California. Worldwide, we could not find a single existing major refinery comprehensively retrofitted with CCS. Much smaller demonstration projects exist in sections of refineries, such as refinery hydrogen plants (steam methane reformers) and one small, newly built Canadian refinery which includes CCS in a spacious rural area.[2]

By contrast, California refineries are massive complexes, with hundreds of refinery boilers, heaters, and other combustion stacks, interspersed with miles of complex piping and storage tanks, and most surrounded by neighbors and businesses.[3] That most California refineries are highly space-constrained is well-documented, for instance, in South Coast Air Quality Management District (SCAQMD) Rulemaking 1109.1. Adding widespread CCS to hundreds of boilers and heaters presents a major safety hazard according to expert studies, making the assumption of widespread refinery CCS use not only improbable but dangerous, if forced.

To make assumed CCS numbers visible, we used the newly released assumptions data to total Refinery CCS amounts each year for four refinery fuels evaluated in E3 modeling (petroleum coke, pipeline gas, petroleum and process gas, and waste heat) for Alternative 3, from the "CCS by fuel" sheet. We graphed it as follows (specific numbers are provided at the end of this factsheet).



[1] 2022 Draft Scoping Plan, Modeling Information, AB 32 GHG Inventory Sectors Modeling Data Spreadsheet, last Sheet in Excel spreadsheet is CCS by fuel.

[2] For more on the low capture rates and high cost of three operational steam methane reformer demonstration projects, none of which comport with CARB's "at the stack" 90% capture rate assumption, please see Stanford academic comment letters. Wara, Michael et al, May 3, 2022, www.arb.ca.gov/lists/com-attach/62-sp22-econ-health-ws-VDVSJgNgVloBdAVm.pdf and Wara, Michael et al, https://www.arb.ca.gov/lists/com-attach/65-sp22-modelresults-ws-BWQFcVMwUFxWI1Az.pdf.

[3] For more detail on the physical limitations and hazards at California's refineries, see May, Julia, CBE, April 4, 2022, CBE Comments on Scoping Modeling – Refineries, Re: CARB Draft Scoping Plan: AB32 Source Emissions Initial Modeling Results, pp. 4-10, available at CARB comment portal.

The projected cumulative totals of carbon dioxide removed by CCS at refineries reach:

- ► 2021-2025: 27.6 million (metric tonnes)
- ► 2026-2030: another 60 million
- ► 2031-2035: another 56.4 million
- ► 2036-2045: another 57 million

Carbon capture at California refinery hydrogen plants must be considered *within the entire refinery system*. At the Initial Modeling Workshop, CARB indicated it was using a 90%[4] capture rate "at the stack."[5] Yet no such rate has been demonstrated at a refinery hydrogen plant.[6] As entirely new technology to California oil refineries, CCS in refineries face several years, if not at least a decade to be a serious consideration for operation, after site-specific engineering design, development of refinery-specific regulatory frameworks, site-specific environmental review, construction, and de-bugging.

CARB's imaginary CCS, even if implemented, would allow continued emissions throughout most of the refinery, be publicly subsidized, very costly, delay and undermine the real goal – phasing out fossil fuel infrastructure. The absence of a formal plan to manage the decline of oil refining in California by 2045 is shockingly missing from the Draft Scoping Plan. This transition planning is needed so that communities and workers have certainty in their transition to accompany the transition to zero emission cars and trucks, and in order to survive the climate disaster, as well as the public health crisis from smog.

Alternative 3 Refinery CCS Totals Each Year *(Tonnes CO2)* are as follows:

2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
2,003,225	3,740,895	5,691,755	7,334,956	8,860,179	10,116,780	11,402,646	12,129,938	12,903,767	13,504,086

2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
12,840,721	12,037,585	11,451,916	10,502,560	9,613,486	8,910,653	7,929,212	7,134,874	6,455,638	5,817,768

2041	2042	2043	2044	2045
5,164,447	4,606,671	4,097,655	3,644,028	3,213,948

See Attachments A & B for detailed Refinery Data from E3 modeling.

For more information, contact: Julia May, Senior Scientist, or Connie Cho, Attorney, CBE

Last updated: May 13, 2022

[4] Mahone et al., CARB Draft Scoping Plan: AB 32 Source Emissions Initial Modeling Results, Slide 10 - Oil & Gas Extraction and Petroleum Refining Emissions, Mar. 15, 2022, https://ww2.arb.ca.gov/sites/default/files/2022-03/SP22-Model-Results-E3-ppt.pdf.
[5] CARB Deputy Executive Rajinder Sahota clarified in verbal comments at the Workshop and the following EJAC meeting.
[6] See Footnote 2 and Footnote 3.

Attachment A Refinery CCS: Excerpt from Scoping Plan E3 Spreadsheets: *CCS Captured Emissions By Fuel, Post-combustion* – Refineries, Alt 3 (tCO2) (CBE added totals)

Fuel	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Coke	431,902	810,353	1,241,882	1,613,147	1,958,683	2,250,237	2,550,208	2,731,180	2,925,039	3,083,143
Pipeline Gas	679,251	1,261,687	1,938,415	2,518,790	3,032,947	3,445,594	3,868,705	4,089,664	4,322,966	4,491,074
Refinery & Process Gas	830,344	1,553,467	2,373,925	3,074,842	3,722,879	4,264,933	4,819,836	5,147,344	5,497,234	5,778,156
Waste Heat	61,729	115,388	137,533	128,178	145,669	156,016	163,897	161,750	158,528	151,713
Total	2,003,225	3,740,895	5,691,755	7,334,956	8,860,179	10,116,780	11,402,646	12,129,938	12,903,767	13,504,086

Fuel	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Coke	2,947,821	2,779,721	2,659,595	2,457,293	2,266,784	2,117,399	1,903,309	1,730,080	1,582,601	1,442,878
Pipeline Gas	4,253,353	3,968,189	3,758,179	3,418,846	3,101,734	2,849,233	2,499,625	2,216,619	1,972,258	1,744,383
Refinery & Process Gas	5,509,131	5,180,516	4,942,886	4,554,268	4,189,592	3,902,720	3,498,487	3,171,371	2,893,112	2,630,508
Waste Heat	130,417	109,159	91,256	72,153	55,376	41,301	27,791	16,804	7,667	-
Total	12,840,721	12,037,585	11,451,916	10,502,560	9,613,486	8,910,653	7,929,212	7,134,874	6,455,638	5,817,768

Fuel	2041	2042	2043	2044	2045
Coke	1,298,900	1,176,350	1,066,569	967,491	872,809
Pipeline Gas	1,503,952	1,297,331	1,102,375	931,705	771,288
Refinery & Process Gas	2,361,595	2,132,990	1,928,711	1,744,833	1,569,851
Waste Heat	-	-	-	-	-
Total	5,164,447	4,606,671	4,097,655	3,644,028	3,213,948

Attachment B: REFINERY EMISSIONS: Excerpts, totaled from E3 Spreadsheets: Refinery BAU, Alt 3 & CCS we totaled from two sheets: Energy GHG Details, and CCS by Fuel.

Below these, we showed BAU minus refinery CCS, to show that there is another unidentified Refinery emission reduction assumed (from Cap & Trade? or lower demand? – this is not identified). **Since there are no proposed *requirements* for refineries to reduce production, this appears to be another unrealistic assumption, especially since Refinery GHGs have not gone down under Cap & Trade.** (This sheet in is in million tonnes, previous page in tonnes.)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
BAU	33.31	31.09	31.57	31.28	30.94	30.22	29.98	28.75	28.06	27.38
Alt 3 Total emissions	31.27	27.24	25.62	22.92	20.38	17.64	15.34	12.71	10.54	8.53
Alt 3 CCS	2.00	3.74	5.69	7.33	8.86	10.12	11.40	12.13	12.90	13.50
BAU minus CCS*	31.31	27.35	25.88	23.94	22.08	20.10	18.58	16.62	15.15	13.88

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
BAU	26.93	26.22	26.06	25.23	24.74	24.82	24.15	23.83	23.77	23.69
Alt 3 Total emissions	8.10	7.59	7.21	6.60	6.03	5.57	4.95	4.44	4.01	3.61
Alt 3 CCS	12.84	12.04	11.45	10.50	9.61	8.91	7.93	7.13	6.46	5.82
BAU minus CCS*	14.09	14.18	14.61	14.73	15.12	15.91	16.22	16.70	17.32	17.88

	2041	2042	2043	2044	2045
BAU	23.36	23.20	23.10	23.02	22.85
Alt 3 Total emissions	3.20	2.85	2.53	2.25	1.98
Alt 3 CCS	5.16	4.61	4.10	3.64	3.21
BAU minus CCS*	18.19	18.60	19.00	19.37	19.63

Attachment B

Extracted from Title V permit by J. May, CBE Oct. 2022			Tesoro (Maraton) Carson CA Refinery: 174655 From Title V permit - 6/24/22 TiV: http://onbase-pub.aqmd.gov/publicaccess/PublicAccessProvider.ashx?action=ViewDocument&overlay=Print&overrideFormat=PDF		
Facility ID	Applic. Number	Size (MMBTU /hr)	From Ti5 permit Unit ID #	From Ti5 permit System / Process	
174655	553016	985.50	D1226	Electricity Generation	Gas Turbine w 2 gas stop ratio valves
174655	552815	650	D570	Hydrogen Production	Heater, Hydrogen Plant, Primary Reformer (pdf 116)
174655	552867	550	D27	Crude Dist. Unit Heaters	Heater, No. 1 Crude Oil Distillation (pdf p. 19)
174655	552818	427	D1465	Hydrogen Production	Heater RW0054, Hydrogen Reforming (pdf 116)
174655	App# Miss	360	D63	Vacuum Distill. Unit Htrs	Heater No. 51, Vacuum Unit Distillation (pdf. 24)
174655	552797	310	D535	Catalytic Reforming	Heater No. 2 Reformer #015 (pdf 107)
174655	552962	255	D532	Cat Reform. Unit Heaters	Heater No. 1 Reformer 014 (pdf 106)
174655	552945?	173	D629	Hydrocracking	Heater, Reboiler No. 017, Hydrocracker Fractionator (pdf 125)
174655	552802	171	D1439	Catalytic Reforming	Heater, No. 3 Reformer, No. 016 (pdf 107)
174655	552927	165.0	D2837	Fluid Catalytic Cracking	Heater RPV 2319, Regenerator Startup Air Heater
174655	552796	150	D29	Crude Dist. Unit Heaters	System 4- Heater, No. 21, No. 2 Crude Oil Distillation (pdf. 19)
174655	552937	130	D151	Coking & Resid. Conditioning	Heater, No. 1 Delayed Coker Unit (West) (pdf. 38)
174655	552896	130	D153	Coking & Resid. Conditioning	Heater, No. 1 Delayed Coker Unit (East) (pdf. 38)
174655	552891	130	D155	Coking & Resid. Conditioning	Heater, Delayed Coker Unit No. 2 (pdf. 38)
174655	552804	130	D31	Crude Oil Distillation Charge	Heater, No. 4 Crude Oil Distillation Charge (pdf. 20)
174655	552833	120	D67	Crude Oil Distillation	Heater, No. 52 Vacuum Unit (pdf 25)
174655	552799	100	D33	Crude Oil Distillation	Heater No. 22, No. 2 Crude Oil Distillation (pdf. 20)
174655	552923	89.0	D250	Fluid Catalytic Cracking	Heater, Fluid Cat Cracking Feed (pdf 57)
174655	552936	82	D421	Hydrotreating	Heater No. 018, Mid-barrel Stabilizer Reboiler (pdf p. 89)
174655	552919	80	D423	Hydrotreating	Heater FCC HDS (HydroDesulfurization Unit) (pdf p. 89)
174655	552959	52	D539	Catalytic Reforming	Heater, No. 1 Reformer Desulfurizer, (pdf p. 108)
174655	552943	52	D419	Hydrotreating	Heater No. 018, Mid-barrel Stabilizer Reboiler (pdf p. 89)
174655	552806	39	D538	Catalytic Reforming	Heater No. 2A, Process Reformer (pdf 108)
174655	552965	39	D541	Proc 6: Cat Reforming	Heater No. 2, Desulfurizer No. 2B (pdf 109)
174655	553164	39	D625	Hydrocracking	Heater, No. R1 (pdf 123)
174655	552925	39	D627	Hydrocracking	Heater No. R2 Recycle Gas (pdf 124)
174655	552899	39	D626	Hydrocracking	Heater No. R4 (pdf 123)
174655	552940	39	D628	Hydrocracking	Heater No. R3 Recycle Gas (pdf 124)
174655	552922	24	D416	Hydrotreating	Heater, Jet Treater R-1 (pdf p. 87)
174655	552934	22	D425	Hydrotreating	Heater Light Gasoline Hydrogenation Feed (pdf p. 90)
174655	552939	12.5	D1433	Hydrotreating	Heater, RW 0053, Naphtha HDS Reactor (pdf 91)
174655	552926	11	D418	Hydrotreating	Heater, Jet Treater R-3 (pdf p. 88)
174655	552930	10	D417	Hydrotreating	Heater, Jet Treater Stabilizer Reboiler (pdf p. 88)
174655	552931	4.9	D252	Fluid Catalytic Cracking	Propylene Tetramer Reboiler (pdf 57)
174655	552842	3.9	D69	Crude Distillation	Slop Oil Rerun Unit Heaters (pdf 25)
	Total	5,614			
	>90% of Total	5107.50 0.91	Rows 3-22		