Technical Report by Greg Karras

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Regarding the
Martinez Refinery Renewable Fuels Project
Draft Environmental Impact Report, County
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Lead Agency
Contra Costa County

Contents

Scope of Review

In October 2021 Contra Costa County ("the County") made available for public review a Draft Environmental Impact Report ("DEIR") for the Martinez Refinery Renewable Fuels Project ("project"). The project would, among other things, repurpose selected petroleum refinery process units and equipment from the shuttered Marathon Martinez refinery for processing lipidic (oily) biomass to produce biofuels. Prior to DEIR preparation, people in communities adjacent to the project, environmental groups, community groups, environmental justice groups and others raised numerous questions about potential environmental impacts of the project in scoping comments.

This report reviews the DEIR project description, its evaluations of potential impacts associated with emission-shifting on climate and air quality, refinery process changes on hazards, and refinery flaring on air quality, and its analysis of the project baseline.

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[1] The author's curriculum vitae and publications list are appended hereto as Attachment 1.

1. PROJECT DESCRIPTION AND SCOPE

Accurate and complete description of the project is essential to accurate analysis of its potential environmental impacts. In numerous important instances, however, the DEIR does not provide this essential information. Available information that the DEIR does not disclose or describe will be necessary to evaluate potential impacts of the project.

1.1 Type of Biofuel Technology Proposed

Biofuels—hydrocarbons derived from biomass and burned as fuels for energy—are made via many different technologies, each of which features a different set of capabilities, limitations, and environmental consequences. See the introduction to *Changing Hydrocarbons Midstream*, appended hereto as Attachment 2, for examples.[2] [3] However, the particular biofuel technology that the project proposes to use is not identified explicitly in the DEIR. Its reference to "renewable fuels" provides experts in the field a hint, but even then, several technologies can make "renewable fuels,"[4] [5] and the DEIR does not state which is actually proposed.

Additional information is necessary to infer that, in fact, the project as proposed would use a biofuel technology called "Hydrotreated Esters and Fatty Acids" (HEFA).

1.1.1 Available evidence indicates that the project would use HEFA technology.

That this is a HEFA conversion project can be inferred based on several converging lines of evidence. First, the project proposes to repurpose the same hydro-conversion processing units that HEFA processing requires along with hydrogen production required by HEFA processing,[6] hydrotreating, hydrocracking and hydrogen production units.[7] Second, it does not propose to

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[2] Karras, 2021a. *Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing;* prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting. Appended hereto as Attachment 2 (Att. 2).
[3] Attachments to this report hereinafter are cited in footnotes.
[4] Karras. 2021b. *Unsustainable Aviation Fuels: An assessment of carbon emission and sink impacts from biorefining and feedstock choices for producing jet biofuel from repurposed crude refineries;* Natural Resources Defense Council (NRDC). Prepared for the NRDC by Greg Karras, G. Karras Consulting. Appended hereto as Attachment 3.
[5] See USDOE, 2021. *Renewable Hydrocarbon Biofuels;* U.S. Department of Energy, accessed 29 Nov 2021 at https://afdc.energy.gov/fuels/emerging_hydrocarbon.html and appended hereto as Attachment 3 ("Renewable diesel is a hydrocarbon produced through various processes such as hydrotreating, gasification, pyrolysis, and other biochemical and thermochemical technologies").
[6] Karras, 2021a (Att. 2).
[7] DEIR p. 2-16 ("hydrogen plants at the Refinery would provide hydrogen to the Hydrotreating and Hydrocracking Units to support the hydrodeoxygenation (HDO) and isomerization reactions required" to make renewable fuels).

repurpose, build or use biomass feedstock gasification,[8] which is required by commercially proven alternative renewable fuels technologies, but is not needed for HEFA processing. Third, the project proposes to acquire and pretreat lipidic (oily) biomass such as vegetable oils, animal fats and their derivative oils,[9] a class of feedstocks required for HEFA processing but not for the alternative biomass gasification technologies, which is generally more expensive than the cellulosic biomass feedstocks those technologies can run.[10] Fourth, the refiner would be highly incentivized to repurpose idled refining assets for HEFA technology instead of using another "renewable" fuel technology, which would not use those assets.[11] Finally, in other settings HEFA has been widely identified as the biofuel technology that this and other crude-to-biofuel refinery conversion projects have in common.

With respect to the DEIR itself, however, people who do not already know what biofuel technology is proposed may never learn that from reading it, without digging deeply into the literature outside the document for the evidence described above.

1.1.2 <u>Inherent capabilities and limitations of HEFA technology</u>.

Failure to clearly identify the technology proposed is problematic for environmental review because choosing to rebuild for a particular biofuel technology will necessarily afford the project the particular capabilities of that technology while limiting the project to its inherent limitations.

A unique capability of HEFA technology is its ability to use idled petroleum refining assets for biofuel production—a crucial environmental consideration given growing climate constraints and crude refining overcapacity.[12] Another unique capability of HEFA technology is its ability to produce "drop-in" diesel biofuel that can be added to and blended with petroleum distillates in the existing liquid hydrocarbon fuels distribution and storage system, and internal combustion transportation infrastructure.[13] In this respect, the DEIR omits the basis for evaluating whether the project could result in combustion emission impacts by adding biofuel to the liquid combustion fuel chain infrastructure of petroleum.

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[8] DEIR Table 2-1 (new or repurposed equipment to gasify biomass excluded).
[9] DEIR p. 2-1 (proposed project would "switch to ... feedstock sources including rendered fats, soybean and corn oil, and potentially other cooking and vegetable oils ...").
[10] Karras, 2021a (Att. 2).
[11] *Id.*
[12] *Id.*
[13] *Id.*

Inherent limitations of HEFA technology that are important to environmental review include high process hydrogen demand, low fuels yield on feedstock—especially for jet fuel and gasoline blending components—and limited feedstock supply.[14]

The DEIR does not disclose or describe these uniquely important capabilities and limitations of HEFA technology, and thus the project. Environmental consequences of these undisclosed project capabilities and limitations are discussed throughout this report below.

1.1.3 Potential project hydrogen production technologies.

Despite the inherently high process hydrogen demand of proposed project biorefining the DEIR provides only a cursory and incomplete description of proposed and potential hydrogen supply technologies. The DEIR does not describe the technology used by existing onsite hydrogen plants proposed to be repurposed by the project. These hydrogen plants use fossil fueled hydrogen steam reforming technology. This fossil gas steam reforming would co-produce roughly ten tons of carbon dioxide (CO_2) emission with each ton of hydrogen supplied to project biofuel processing,[15] but the basis for knowing to evaluate that potential impact is obscured by omission in the DEIR.

The DEIR identifies a non-fossil fuel hydrogen production technology—splitting water to co-produce hydrogen and oxygen using electricity from renewable resources—then ranks its impacts in relation to the project with fossil gas steam reforming without describing either of those hydrogen alternatives adequately to support reasonable environmental comparison. Reading the DEIR, one would not know that electrolysis can produce zero-emission hydrogen while steam reforming emits some ten tons of CO_2 per ton of hydrogen produced.

Another hydrogen supply option is left undisclosed. The DEIR does not disclose that existing naphtha reforming units co-produce hydrogen[16] as a byproduct of their operation, or describe the potential that the reformers might be repurposed to process partially refined petroleum while supplying additional hydrogen for expanded HEFA biofuel refining onsite.[17]

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[14] Karras, 2021b (Att. 3).

[15] *Id.* (median value from multiple Bay Area refinery steam reforming plants of 9.82 g CO_2/g H_2 produced)

[16] See Chevron Refinery Modernization Project, SCH# 2011062042, DEIR Appendix 4.3–URM: Unit Rate Model, appended hereto as Attachment 5.

[17] The naphtha reformers could supply additional hydrogen for project biorefining if repurposed to process petroleum gasoline feedstocks imported to ongoing refinery petroleum storage and transfer operations.

1.2 Process Chemistry and Reaction Conditions

HEFA processing reacts lipidic (oily) biomass with hydrogen over a catalyst at high temperatures and extremely high pressures to produce deoxygenated hydrocarbons, and then restructures those hydrocarbons so that they can be burned as diesel or jet fuel.[18] Except for naming the two separate processing steps that would use hydrogen in repurposed refinery hydro-conversion process units to deoxygenate the feed (hydrodeoxygenation) and restructure the deoxygenated hydrocarbons (isomerization), the DEIR does not describe the project biofuel processing chemistry or reaction conditions. The DEIR thus does not describe environmentally significant differences in HEFA refining compared with petroleum refining, impacts of feed choices and product targets in project biofuel processing, or changes in the process conditions of repurposed refinery hydro-conversion process units.[19]

1.2.1 Key differences in processing compared with petroleum refining

HEFA technology is based on four or five central process reactions which are not central to or present in crude petroleum processing. Hydrodeoxygenation (HDO) removes the oxygen that is concentrated in HEFA feeds: this reaction is not present in refining crude, which contains little or no oxygen.[20] Depropanation is a precondition for completion of the HDO reaction: a condition that is not present in crude refining but needed to free fatty acids from the triacylglycerols in HEFA feeds.[21] Saturation of the whole HEFA feed also is a precondition for complete HDO: this reaction does not proceed to the same extent in crude refining.[22] Each of those HEFA process steps react large amounts of hydrogen with the feed.[23]

Isomerization is then needed in HEFA processing to "dewax" the long straight-chain hydrocarbons from the preceding HEFA reactions in order to meet fuel specifications, and is performed in a separate process reactor: isomerization of long-chain hydrocarbons is generally absent from petroleum refining.[24] Fuel products from those HEFA process reaction steps include

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[18] Karras, 2021a (Att. 2)

[19] Karras 2021a (Att. 2) and 2021b (Att. 3) provide examples of that show the DEIR could have described changes in processing chemistry and conditions that would result from the project switch to HEFA technology in relevant detail for environmental analysis. Key points the DEIR omitted are summarized in this report section.

[20] Karras, 2021a (Att. 2).

[21] *Id.*

[22] *Id.*

[23] *Id.*

[24] *Id.*

HEFA diesel, a much smaller volume of HEFA jet fuel (without intentional hydrocracking), and little or no gasoline: petroleum crude refining in California yields mostly gasoline with smaller but still significant volumes of diesel and jet fuel.[25] The remarkably low HEFA jet fuel yield can be boosted to roughly 50% on HEFA feed mass, by adding intentional hydrocracking in or separately from the isomerization step, but at the expense of lower overall liquid fuels yield and a substantial further increase in the already-high hydrogen process demand of HEFA refining.[26]

None of these unique aspects of HEFA biofuel processing is described in the DEIR though each must be evaluated for potential project impacts as discussed below.

1.2.2 Relationships between feedstock choices, product targets and hydrogen inputs

HEFA process hydrogen demand exceeds that of petroleum refining by a wide margin generally, however, both HEFA feedstock choices and HEFA product targets can affect project hydrogen demand for biofuel processing significantly. Among other potential impacts, increased hydrogen production to supply project biorefining would increase CO_2 emissions as discussed in § 1.1.3. The DEIR, however, does not describe these environmentally relevant effects of project feed and product target choices on project biofuel refining.

Available information excluded from the DEIR suggests that choices between potential feedstocks identified in the DEIR[27] could result in a difference in project hydrogen demand of up to 0.97 kilograms per barrel of feed processed (kg H_2/b), with soybean oil accounting for the high end of this range.[28] Meanwhile, targeting jet fuel yield via intentional hydrocracking could increase project hydrogen demand by up to 1.99 kg H_2/b.[29] Choices of HEFA feedstock and product targets in combination could change project hydrogen demand by up to 2.81 kg H_2/b.[30]

Climate impacts that are identifiable from this undisclosed information appear significant. Looking only at hydrogen steam reforming impacts alone, at its 48,000 b/d capacity the feed choice (0.97 kg H_2/b), products target (1.99 kg H_2/b), and combined effect (2.81 kg H_2/b)

[25] *Id.*
[26] Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[27] DEIR p. 2-1 (proposed project would "switch to ... feedstock sources including rendered fats, soybean and corn oil, and potentially other cooking and vegetable oils ...").
[28] Karras, 2021b (Att. 3).
[29] *Id.*
[30] *Id.*

impacts estimated above could result in emission increments of 168,000, 342,000, and 485,000 metric tons of CO_2 emission per year, respectively, from project steam reforming alone. These potential emissions compare with the DEIR significance threshold of 10,000 metric tons/year.[31] Most significantly, even the low end of the emissions range for combined feed choice and product target effects, for feeds identified by the DEIR and HEFA steam reforming alone, exceeds the average total carbon intensity of U.S. petroleum crude refining by 4.4 kg CO_2/b (10%) while the high end exceeds that U.S. crude refining CI by 32 kg CO_2/b (77%).[32] [33]

The DEIR project description obscures these potential impacts of the project, among others.

1.2.3 Changes in process conditions of repurposed equipment

With the sole exception of maximum fresh feed input, the DEIR does not disclose design specifications for pre-project or post-project hydro-conversion process unit temperature, pressure, recycle rate, hydrogen consumption, or any other process unit-specific operating parameter. This is especially troubling because available information suggests that the project could increase the severity of the processing environment in the reactor vessels of repurposed hydro-conversion process units significantly.

In one important example, the reactions that consume hydrogen in hydro-conversion processing are highly exothermic: they release substantial heat.[34] Further, when these reactions consume more hydrogen the exothermic reaction heat release increases, and HEFA refining consumes more hydrogen per barrel of feed than petroleum refining.[35] Hydro-conversion reactors of the types to be repurposed by the project operate at temperatures of some 575–780 ºF and pressures of some 600–2,800 pound-force per square inch in normal conditions, when processing petroleum.[36] These severe process conditions could become more severe processing HEFA feeds. The project could thus introduce new hazards. Sections 3 and 4 herein review potential process hazards and flare emission impacts which could result from the project, but yet again, information the DEIR does not disclose or describe will be essential to full impacts evaluation.

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[31] HEFA emission estimates based on per-barrel steam reforming CO_2 emissions from Table 5 in Attachment 3.
[32] *Id.*
[33] Average U.S. petroleum refining carbon intensity from 2015–2017 of 41.8 kg CO_2/b crude from Attachments 2, 3.
[34] Karras, 2021a (Att. 2).
[35] *Id.*
[36] *Id.*

1.3 Process Inputs

The project would switch the oil refinery from crude petroleum to a new and very different class of oil feeds—triacylglycerols of fatty acids. Switching to new and different feedstock has known potential to increase refinery emissions[37] and to create new and different process hazards[38] [39] and feedstock acquisition impacts.[40] Such impacts are known to be related to either the chemistries and processing characteristics of the new feeds, as discussed above, or to the types and locations of extraction activities to acquire the new feeds. However, the DEIR does not describe the chemistries, processing characteristics, or types and locations of feed extraction sufficiently to evaluate potential impacts of the proposed feedstock switch.

1.3.1 Change and variability in feedstock chemistry and processing characteristics

Differences in project processing impacts caused by differences in refinery feedstock, as discussed above, are caused by differences in the chemistries and processing characteristics among feeds that the DEIR does not disclose or describe. For example, feed-driven differences in process hydrogen demand discussed above both boost the carbon intensity of HEFA refining above that of petroleum crude refining, and boost it further still for processing one HEFA feed instead of another. The first impact is driven mainly by the uniformly high oxygen content of HEFA feedstocks, while the second—also environmentally significant, as shown—is largely driven by differences in the number of carbon double bonds among HEFA feeds.[41] This difference in chemistries among HEFA feeds which underlies that significant difference in their processing characteristics can be quantified based on available information. Charts 1.A–1.F, excerpted from Attachment 2, show the carbon double bond distributions across HEFA feeds.

The DEIR could have reported and described this information that allows for process impacts of potential project feedstock choices to be evaluated, but unfortunately, it did not.

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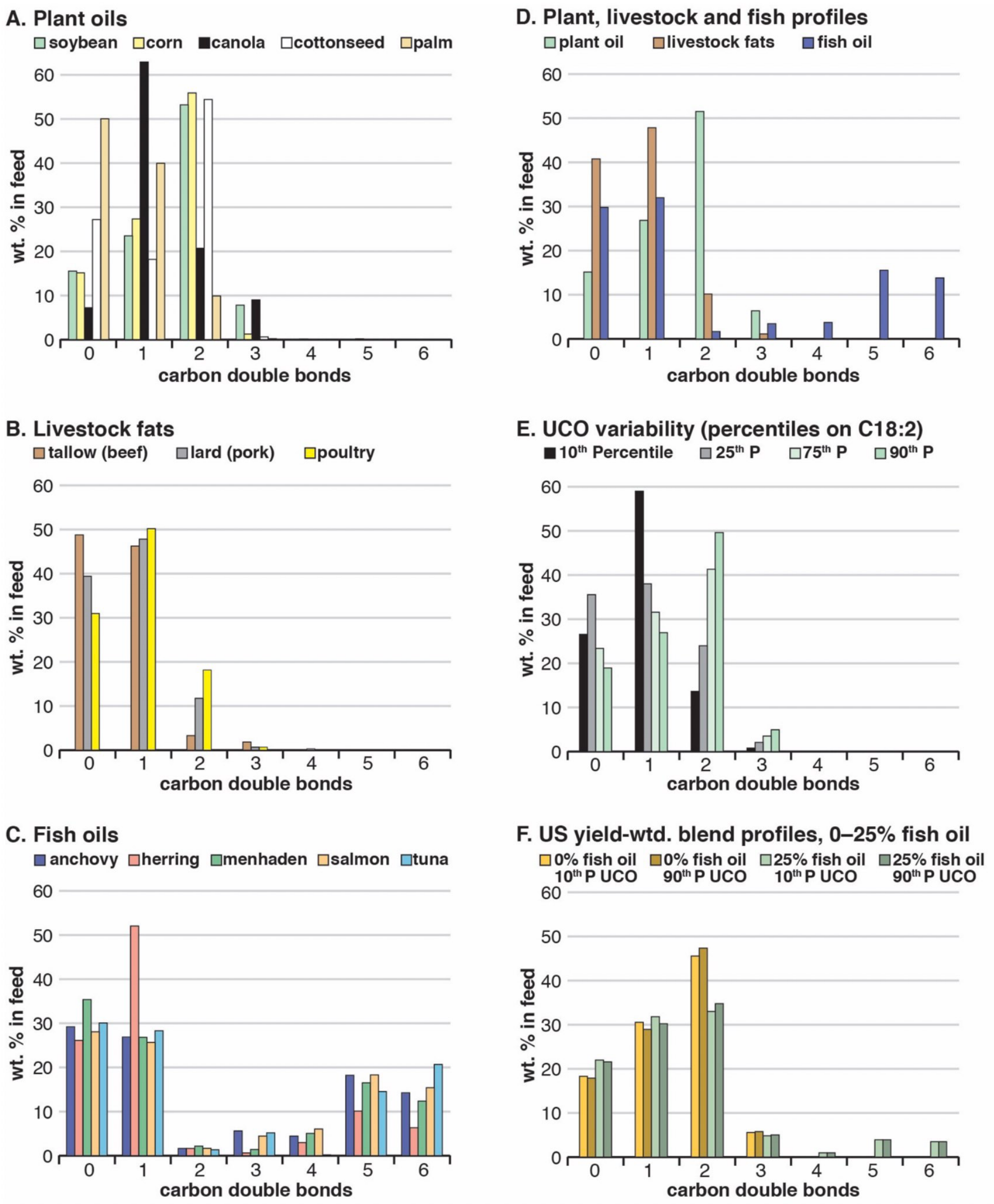
[37] *See* Karras, 2010. Combustion Emissions from Refining Lower Quality Oil: What is the global warming potential? *Environ. Sci. Technol.* 44(24): 9584–9589. DOI: 10.1021/es1019965. Appended hereto as Attachment 6.

[38] *See* CSB, 2013. *Interim Investigation Report, Chevron Richmond Refinery Fire;* U.S. Chemical Safety Board: Washington, D.C. https://www.csb.gov/file.aspx?Documentid=5913. Appended hereto as Attachment 7.

[39] *See* API, 2009. *Guidelines for Avoiding Sulfidation (Sulfidic) Corrosion Failures in Oil Refineries;* API Recommended Practice 939-C. First Edition, May 2009. American Petroleum Institute: Washington, D.C. Appended hereto as Attachment 8.

[40] *See* Krogh et al., 2015. *Crude Injustice on the Rails: Race and the disparate risk from oil trains in California;* Communities for a Better Environment and ForestEthics. June 2015. Appended hereto as Attachment 9.

[41] *See* Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).



1. HEFA feed fatty acid profiles by number of carbon double bonds.
Carbon double bonds require more hydrogen in HEFA processing. **A–C.** Plant oil, animal fat and fish oil profiles. **D.** Comparison of weighted averages for plant oils (US farm yield-wtd. 70/20/7/3 soy/corn/canola/cottonseed blend), livestock fats (40/30/30 tallow/lard/poultry blend) and fish oils (equal shares for species in Chart 1C). **E.** UCO: used cooking oil, a highly variable feed. **F.** US yield-weighted blends are 0/85/10/5 and 25/60/10/5 fish/plant/livestock/UCO oils. Profiles are median values based on wt.% of linoleic acid. *See* Table A1 for data and sources.[1]

1.3.2 Types and locations of potential project biomass feed extraction

HEFA biofuel technology is limited to lipidic (oily) feedstocks produced almost exclusively by land-based agriculture, and some of these feeds are extracted by methods that predictably cause deforestation and damage carbon sinks in Amazonia and Southeast Asia.[42] However, the DEIR does not describe the types and locations of potential project biomass feed extraction activities.

1.4 Project Scale

Despite the obvious relationship between the scale of an action and its potential environmental impacts, the DEIR does not describe the scale of the project in at least two crucial respects. First, the DEIR does not describe its scale relative to other past and currently operating projects of its kind. This omission is remarkable given that available information indicates the project could become among the largest HEFA refineries to be built worldwide—second perhaps only to the concurrently proposed HEFA conversion project in nearby Rodeo.[43]

Second, the DEIR does not describe the scale of proposed feedstock demand. Again, the omission is remarkable. As documented in Attachment 3 hereto, total U.S. production (yield) for all uses of the specific types of lipids which also have been tapped as HEFA feedstocks—crop oils, livestock fats and, to a much lesser degree, fish oils, can be compared with the 48,000 b/d (approximately 2.55 million metric tons/year) proposed project feedstock capacity. *See* Table 1.

This feedstock supply-demand comparison (Table 1) brings into focus the scale of the project, and the related project proposed by Phillips 66 in Rodeo, emphasizing the feedstock supply limitation of HEFA technology discussed in § 1.1.2. Several points bear emphasis for context: The table shows total U.S. yields for *all uses* of lipids that also have been HEFA feedstocks, including use as food, livestock feed, pet food, and for making soap, wax, cosmetics, lubricants and pharmaceutical products, and for exports.[44] These existing uses represent commitments of finite resources, notably cropland, to human needs. Used cooking oils derived from primary sources shown are similarly spoken for and in even shorter supply. Lastly, HEFA feeds are limited to lipids (shown) while most other biofuels are not, but multiple other HEFA refineries are operating or proposed besides the two Contra Costa County projects shown.

[42] *See* Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).
[43] Karras, 2021a (Att. 2).
[44] Karras, 2021b (Att. 3).

Table 1. Project Feed Demand *v.* U.S. Total Yield of Primary HEFA Feed Sources for All Uses.

MM t/y: million metric tons/year

HEFA Feed-stock Type	U.S. Yield [a] (MM t/y)	Project and County-wide feedstock demand (% of U.S. Yield)		
		Marathon Project [b]	Phillips 66 Project [b]	Both Projects
Fish oil	0.13	1961 %	3269 %	5231 %
Livestock fat	4.95	51 %	86 %	137 %
Soybean oil	10.69	24 %	40 %	64 %
Other oil crops	5.00	51 %	85 %	136 %
Total yield	20.77	12 %	20 %	33 %

a. Total U.S. production for all uses of oils and fats also used as primary sources of HEFA biofuel feedstock. Fish oil data for 2009–2019, livestock fat data from various dates, soybean oil and other oil crops data from Oct 2016–Sep 2020, from data and sources in Att. 3. **b.** Based on project demand of 2.55 MM t/y (48,000 b/d from DEIR), related project demand of 4.25 MM t/y (80,000 b/d from related project DEIR), given the typical specific gravity of soy oil and likely feed blends (0.916) from Att. 2.

In this context, the data summarized in Table 1 indicate the potential for environmental impacts. For example, since the project cannot reasonably be expected to displace more than a fraction of existing uses of any one existing lipids resource use represented in the table, it would likely process soy-dominated feed blends that are roughly proportionate to the yields shown.[45] This could result in a significant climate impact from the soybean oil-driven increase in hydrogen steam reforming emissions discussed in § 1.2.2.

Another example: Feedstock demand from the Contra Costa County HEFA projects alone represents one-third of current total U.S. yield for all uses of the lipids shown in Table 1, including food and food exports. Much smaller increases in biofuel feedstock demand for food crops spurred commodity price pressures that expanded crop and grazing lands into pristine areas globally, resulting in deforestation and damage to natural carbon sinks.[46] The unprecedented cumulative scale of potential new biofuel feedstock acquisition thus warrants evaluation of the potential for the project to contribute to cumulative indirect land use impacts at this new scale.

The DEIR, however, does not attempt either impact evaluation suggested in these examples. Its project description did not provide a sufficient basis for evaluating feedstock acquisition impacts that are directly related to the scale of the project, which the DEIR did not disclose or describe.

[45] Data in Table 1 thus rebut the unsupported DEIR assertion that future project feeds are wholly speculative.
[46] See Karras, 2021a (Att. 2); Karras, 2021b (Att. 3).

1.5 Project Operational Duration

The anticipated and technically achievable operational duration of the project, hence the period over which potential impacts of project operation could occur, accumulate, or worsen, is not disclosed or described in the DEIR. This is a significant deficiency because accurate estimation of impacts that worsen over time requires an accurately defined period of impact review.

Contra Costa County could have accessed many data on the operational duration of the project. The refiner would have designed and financed the project based on a specified operational duration. Since this is necessary data for environmental review it could have and should have been requested and supplied. Technically achievable operational duration data for the types of process units the project proposes to use were publicly available as well. For example, process unit-specific operational data for Bay Area refineries, including the subject refinery, have been compiled, analyzed and reported by Communities for a Better Environment.[47] Information to estimate the anticipated operational duration of the project also can be gleaned from technical data supporting pathways to achieve state climate protection goals,[48] which include phasing out petroleum and biofuel diesel in favor of zero-emission vehicles.

1.6 Project Fuels Market

Potential interactions between the project and the liquid combustion fuels market in California are described in the DEIR,[49] however, it describes potential impacts resulting from imports while omitting any discussion of exports from California refineries or the conditions under which these exports could occur. That description is incomplete and inaccurate. California refineries are net fuel exporters due in large part to structural conditions of statewide overcapacity coupled with declining in-state petroleum fuels demand.[50] [51] [52] The incomplete description of the project fuels market setting can lead to flawed environmental impacts evaluation, as discussed in §§ 2 and 5.

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[47] Karras, 2020. *Decommissioning California Refineries: Climate and Health Paths in an Oil State;* A Report for Communities for a Better Environment. Prepared by Greg Karras. Includes Supporting Material Appendix. www.energy-re-source.com/decomm Appended hereto as Attachment 10.
[48] Karras, 2021a (Att. 2).
[49] DEIR pp. 2-17, 3-3, 3-6, 3.6-9, 3.8-13, 3.9-16, 4-12, 5-4, 5-13.
[50] Karras, 2020 (Att. 10).
[51] USEIA, 2015. West Coast Transportation Fuels Markets; U.S. Energy Information Administration: Washington, D.C. https://www.eia.gov/analysis/transportationfuels/padd5/ Appended hereto as Attachment 11.
[52] USEIA, *Supply and Disposition: West Coast (PADD 5);* U.S. Energy Information Administration: Washington, D.C. ww.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_m_cur.htm. Appended hereto as Attachment 12.

1.7 Project Scope

The DEIR does not describe or disclose a project component that would build intentional hydrocracking capacity into the project to enable increasing HEFA jet fuel production. The 1st Stage Hydrocracker would be repurposed for intentional hydrocracking, unlike the 2nd Stage Hydrocracker, which would be repurposed for isomerization.[53] Unlike that isomerization unit and the #2 and #3 hydro-deoxygenation units, the 1st Stage Hydrocracker could crack up to 24,000 b/d of fresh feed and could not operate independently.[54] This would transform the HEFA refinery into a "Selective Intentional Hydrocracking" configuration that could boost jet fuel yield from roughly half of total project feedstock, and boost it from as little as 13% to as much as 49% by mass on that half of the project feedstock.[55] But in doing so, this hydrocracking-to-boost-jet-yield component would increase refinery hydrogen and resultant project impacts.[56]

The undisclosed project component would be interdependent with disclosed components of the project. The intentional hydrocracking would depend on the project feed acquisition, feed pretreatment, hydrodeoxygenation, and isomerization infrastructure proposed, without which it could not proceed.[57] Disclosed project components, in turn, would depend upon this undisclosed component to boost jet fuel yield and maintain the viability of the biorefinery. In fact boosting the very low jet yield in the absence of intentional cracking[58] could well be a "stay in business" need for the refinery as more efficient battery-electric and fuel-cell-electric vehicles[59] phase out diesel in favor of zero-emission vehicles (ZEVs) pursuant to California state plans and policies.[60]

Crucially, the equipment modifications to implement this hydrocracking-to-boost-jet-yield component are included in the project,[61] but instead of disclosing and describing it for review, the DEIR frames the "potential" for the project to target jet fuel as only an afterthought.[62]

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[53] DEIR pp. 2-20, 2-21; Table 2-1. Refinery Equipment Modifications.
[54] *Id.*
[55] See process description data in Karras, 2021b (Att. 3).
[56] *Id.*
[57] *Id.*
[58] *Id.*
[59] See Karras, 2021a (Att. 2).
[60] *Id.*
[61] DEIR pp. 2-20, 2-21; Table 2-1. Refinery Equipment Modifications.
[62] DEIR p. 6-3 ("The Project would convert ... to the production of renewable fuels, including renewable diesel, renewable propane, renewable naphtha *and potentially renewable jet fuel" [emphasis added]*).

CONCLUSION: The DEIR provides an incomplete, inaccurate, and truncated or at best unstable description of the proposed project. Available information that the DEIR does not describe or disclose will be necessary for sufficient review of environmental impacts that could result from the project.

2. THE DEIR DID NOT CONSIDER A SIGNIFICANT POTENTIAL CLIMATE EMISSION-SHIFTING IMPACT LIKELY TO RESULT FROM THE PROJECT

Instead of replacing fossil fuels, adding renewable diesel to the liquid combustion fuel chain in California resulted in refiners protecting their otherwise stranded assets by increasing exports of petroleum distillates burned elsewhere, causing a net increase in greenhouse gas[63] emissions. The DEIR improperly concludes that the project would decrease net GHG emissions[64] without disclosing this emission-shifting, or evaluating its potential to further increase net emissions. A series of errors and omissions in the DEIR further obscures causal factors for the emission shifting by which the project would cause and contribute to this significant potential impact.

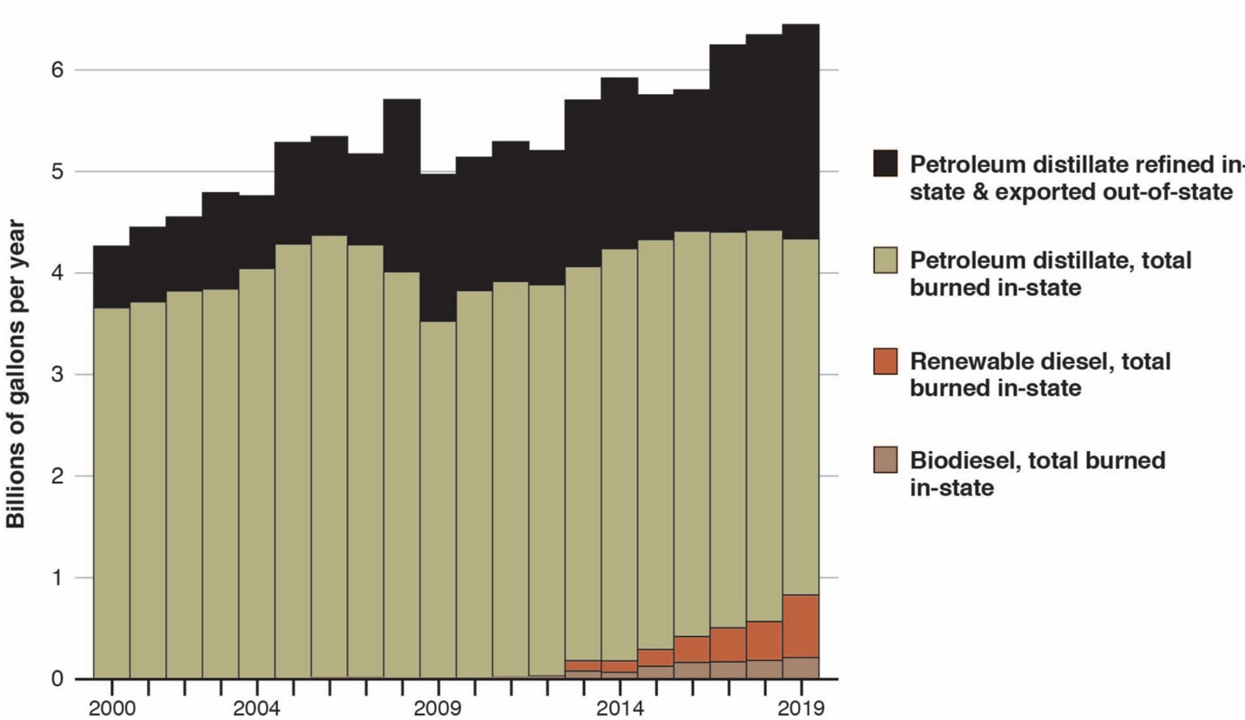
2.1 The DEIR Does Not Disclose or Evaluate Available Data Which Contradict its Conclusion That the Project Would Result in a Net Decrease in GHG Emissions

State law warns against "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state."[65] However, the DEIR does not evaluate this emission-shifting impact of the project. Relevant state data that the DEIR failed to disclose or evaluate include volumes of petroleum distillates refined in California[66] and total distillates—petroleum distillates and diesel biofuels—burned in California.[67] Had the DEIR evaluated these data the County could have found that its conclusion regarding net GHG emissions resulting from the project was unsupported.

As shown in Chart 2, distillate fuels refining for export continued to expand in California as biofuels that were expected to replace fossil fuels added a new source of carbon to the liquid combustion fuel chain. Total distillate volumes, including diesel biofuels burned in-state,

[63] "Greenhouse gas (GHG)," in this section, means carbon dioxide equivalents (CO_2e) at the 100-year horizon.
[64] "Project would result in an overall decrease in emissions ... [including] indirect GHG emissions" (DEIR p. 3.8-20) and "GHG emissions from stationary and mobile sources" (DEIR p. 3.8-22).
[65] CCR §§ 38505 (j), 38562 (b) (8).
[66] CEC *Fuel Watch*. Weekly Refinery Production. California Energy Commission: Sacramento, CA. https://ww2.energy.ca.gov/almanac/petroleum_data/fuels_watch/output.php Appended hereto as Attachment 13.
[67] CARB GHG Inventory. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity; 14th ed.: 2000 to 2019;* California Air Resources Board: Sacramento, CA. Appended hereto as Attachment 14.

petroleum distillates burned in-state, and petroleum distillates refined in-state and exported to other states and nations, increased from approximately 4.3 billion gallons per year to approximately 6.4 billion gallons per year between 2000 and 2019.[68] [69]



Distillate fuel shares associated with all activities in California, 2000–2019.
Growth in total distillates excluding jet fuel and kerosene from State data.
CHART 2. Data from CEC Fuel Watch (Att. 13) and CARB GHG Inventory (Att. 14).

Petroleum distillates refining for export (black in the chart) expanded after in-state burning of petroleum distillate (olive) peaked in 2006, and the exports expanded again from 2012 to 2019 with more in-state use of diesel biofuels (dark red and brown). From 2000 to 2012 petroleum-related factors alone drove an increase in total distillates production and use associated with all activities in California of nearly one billion gallons per year. Then total distillates production and use associated with activities in California increased again, by more than a billion gallons per year from 2012 to 2019, with biofuels accounting for more than half that increment. These state data show that diesel biofuels did not replace petroleum distillates refined in California during the eight years before the project was proposed. Instead, producing and burning more renewable diesel *along with* the petroleum fuel it was supposed to replace emitted more carbon.

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[68] *Id.*
[69] CEC Fuel Watch (Att. 13).

2.2 The DEIR Presents an Incomplete and Misleading Description of the Project Market Setting that Focuses on Imports and Omits Structural Overcapacity-driven Exports, Thereby Obscuring a Key Causal Factor in the Emission-shifting Impact

The DEIR describes potential GHG emissions resulting from imports for the proposed project[70] while ignoring fuels exports from California refineries and conditions under which these exports occur. As a result the DEIR fails to disclose that crude refineries here are net fuels exporters, that their exports have grown as in-state and West Coast demand for petroleum fuels declined, and that the structural overcapacity resulting in this export emissions impact would not be resolved and could be worsened by the project.

Due to the concentration of petroleum refining infrastructure in California and on the U.S. West Coast, including California and Puget Sound, WA, these markets were net exporters of transportation fuels before renewable diesel flooded into the California market.[71] Importantly, before diesel biofuel addition further increased refining of petroleum distillates for export, the structural overcapacity of California refineries was evident from the increase in their exports after in-state demand peaked in 2006. *See* Chart 2 above. California refining capacity, especially, is overbuilt.[72] Industry reactions seeking to protect those otherwise stranded refining assets through increased refined fuels exports as domestic markets for petroleum fuels declined resulted in exporting fully 20% to 33% of statewide refinery production to other states and nations from 2013–2017.[73] West Coast data further demonstrate the strong effect of changes in domestic demand on foreign exports from this over-built refining center.[74] *See* Table 2.

Table 2. West Coast (PADD 5) Finished Petroleum Products: Decadal Changes in Domestic Demand and Foreign Exports, 1990–2019.

Total volumes reported for ten-year periods

	Volume (billions of gallons)		Decadal Change (%)	
Period	Demand	Exports	Demand	Exports
1 Jan 1990 to 31 Dec 1999	406	44.2	—	—
1 Jan 2000 to 31 Dec 2009	457	35.1	+13 %	–21 %
1 Jan 2010 to 31 Dec 2019	442	50.9	–3.3 %	+45 %

Data from USEIA, *Supply and Disposition* (Att. 12).

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70 DEIR p. 4-12
71 USEIA, 2015 (Att. 11).
72 Karras, 2020 (Att. 10).
73 *Id.*
74 USEIA, *Supply and Disposition* (Att. 12).

Comparisons of historic with recent California and West Coast data further demonstrate that this crude refining overcapacity for domestic petroleum fuels demand that drives the emission-shifting impact is unresolved and would not be resolved by the proposed project and the related Contra Costa County crude-to-biofuel conversion project. Fuels demand has rebounded, at least temporarily, from pre-vaccine pandemic levels to the range defined by pre-pandemic levels, accounting for seasonal and interannual variability. In California, from April through June 2021 taxable fuel sales[75] approached the range of interannual variability from 2012–2019 for gasoline and reached the low end of this pre-COVID range in July, while taxable jet fuel and diesel sales exceeded the maximum or median of the 2012–2019 range in each month from April through July of 2021. See Table 3.

Table 3. California Taxable Fuel Sales Data: Return to Pre-COVID Volumes

Fuel volumes in millions of gallons (MM gal.) per month

	Demand in 2021	Pre-COVID range (2012–2019) Minimum	Median	Maximum	Comparison of 2021 data with the same month in 2012–2019
Gasoline (MM gal.)					
Jan	995	1,166	1,219	1,234	Below pre-COVID range
Feb	975	1,098	1,152	1,224	Below pre-COVID range
Mar	1,138	1,237	1,289	1,343	Below pre-COVID range
Apr	1,155	1,184	1,265	1,346	Approaches pre-COVID range
May	1,207	1,259	1,287	1,355	Approaches pre-COVID range
Jun	1,196	1,217	1,272	1,317	Approaches pre-COVID range
Jul	1,231	1,230	1,298	1,514	Within pre-COVID range
Jet fuel (MM gal.)					
Jan	10.74	9.91	11.09	13.69	Within pre-COVID range
Feb	10.80	10.13	11.10	13.58	Within pre-COVID range
Mar	13.21	11.23	11.95	14.53	Exceeds pre-COVID median
Apr	13.84	10.69	11.50	13.58	Exceeds pre-COVID range
May	15.14	4.84	13.07	16.44	Exceeds pre-COVID median
Jun	17.08	8.67	12.75	16.80	Exceeds pre-COVID range
Jul	16.66	11.05	13.34	15.58	Exceeds pre-COVID range
Diesel (MM gal.)					
Jan	203.5	181.0	205.7	217.8	Within pre-COVID range
Feb	204.4	184.1	191.9	212.7	Exceeds pre-COVID median
Mar	305.4	231.2	265.2	300.9	Exceeds pre-COVID range
Apr	257.1	197.6	224.0	259.3	Exceeds pre-COVID median
May	244.5	216.9	231.8	253.0	Exceeds pre-COVID median
Jun	318.3	250.0	265.0	309.0	Exceeds pre-COVID range
Jul	248.6	217.8	241.5	297.0	Exceeds pre-COVID median

Data from CDTFA, (Att. 15). Pre-COVID statistics are for the same months in 2012–2019. The multiyear monthly comparison range accounts for seasonal and interannual variability in fuels demand. Jet fuel totals may exclude fueling in California for fuels presumed to be burned outside the state during interstate and international flights.

[75] CDTFA, various years. *Fuel Taxes Statistics & Reports;* Cal. Dept. Tax and Fee Admin: Sacramento, CA. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm. Appended hereto as Attachment 15.

West Coast fuels demand in April and May 2021 approached or fell within the 2010–2019 range for gasoline and jet fuel and exceeded that range for diesel.[76] *See* Table 4. In June and July 2021 demand for gasoline exceeded the 2010–2019 median, jet fuel fell within the 2010–2019 range, and diesel fell within the 2010–2019 range or exceeded the 2010–2019 median.[77] Despite this several-month surge in demand the year after the Marathon Martinez refinery closed, California and West Coast refineries supplied the rebound in fuels demand while running well below capacity. Four-week average California refinery capacity utilization rates from 20 March through 6 August 2021 ranged from 81.6% to 87.3% (Table 5), similar to those across the

Table 4. West Coast (PADD 5) Fuels Demand Data: Return to Pre-COVID Volumes

Fuel volumes in millions of barrels (MM bbl.) per month

	Demand in 2021	Pre-COVID range (2010–2019)			Comparison of 2021 data with the same month in 2010–2019
		Minimum	Median	Maximum	
Gasoline (MM bbl.)					
Jan	38.59	42.31	45.29	49.73	Below pre-COVID range
Feb	38.54	40.94	42.75	47.01	Below pre-COVID range
Mar	45.14	45.23	48.97	52.53	Approaches pre-COVID range
Apr	44.97	44.99	47.25	50.20	Approaches pre-COVID range
May	48.78	46.79	49.00	52.18	Within pre-COVID range
Jun	48.70	45.61	48.14	51.15	Exceeds pre-COVID median
Jul	50.12	47.33	49.09	52.39	Exceeds pre-COVID median
Jet fuel (MM bbl.)					
Jan	9.97	11.57	13.03	19.07	Below pre-COVID range
Feb	10.35	10.90	11.70	18.33	Below pre-COVID range
Mar	11.08	11.82	13.68	16.68	Below pre-COVID median
Apr	11.71	10.83	13.78	16.57	Within pre-COVID range
May	12.12	12.80	13.92	16.90	Approaches pre-COVID range
Jun	14.47	13.03	14.99	17.64	Within pre-COVID range
Jul	15.31	13.62	15.46	18.41	Within pre-COVID range
Diesel (MM bbl.)					
Jan	15.14	12.78	14.41	15.12	Exceeds pre-COVID range
Feb	15.01	12.49	13.51	15.29	Exceeds pre-COVID median
Mar	17.08	14.12	15.25	16.33	Exceeds pre-COVID range
Apr	15.76	14.14	14.93	16.12	Exceeds pre-COVID median
May	16.94	15.11	15.91	17.27	Exceeds pre-COVID median
Jun	14.65	14.53	16.03	16.84	Within pre-COVID range
Jul	16.94	15.44	16.40	17.78	Exceeds pre-COVID median

Data from USEIA *Supply and Disposition* (Att. 12). "Product Supplied," which approximately represents demand because it measures the disappearance of these fuels from primary sources, i.e., refineries, gas processing plants, blending plants, pipelines, and bulk terminals. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID statistics are for the same month in 2010–2019, thus accounting for seasonal and interannual variability.

[76] USEIA, *Supply and Disposition* (Att. 12).
[77] *Id.*

Table 5. Total California Refinery Capacity Utilization in Four-week Periods of 2021.

barrel (oil): 42 U.S. gallons **barrels/calendar day:** see table caption below

Four-week period	Calif. refinery crude input (barrels/day)	Operable crude capacity (barrels/calendar day)	Capacity utilized (%)
12/26/20 through 01/22/21	1,222,679	1,748,171	69.9 %
01/23/21 through 02/19/21	1,199,571	1,748,171	68.6 %
02/20/21 through 03/19/21	1,318,357	1,748,171	75.4 %
03/20/21 through 04/16/21	1,426,000	1,748,171	81.6 %
04/17/21 through 05/14/21	1,487,536	1,748,171	85.1 %
05/15/21 through 06/11/21	1,491,000	1,748,171	85.3 %
06/12/21 through 07/09/21	1,525,750	1,748,171	87.3 %
07/10/21 through 08/06/21	1,442,750	1,748,171	82.5 %
08/07/21 through 09/03/21	1,475,179	1,748,171	84.4 %
09/04/21 through 10/01/21	1,488,571	1,748,171	85.1 %
10/02/21 through 10/29/21	1,442,429	1,748,171	82.5 %

Total California refinery crude inputs from Att. 13. Statewide refinery capacity as of 1/1/21, after the Marathon Martinez refinery closure, from Att. 16. Capacity in barrels/calendar day accounts for down-stream refinery bottlenecks, types and grades of crude processed, operating permit constraints, and both scheduled and unscheduled downtime for inspection, maintenance, and repairs.

West Coast, and well below maximum West Coast capacity utilization rates for the same months in 2010–2019 (Table 6).[78] [79] [80] Moreover, review of Table 5 reveals 222,000 b/d to more than 305,000 b/d of spare California refinery capacity during this fuels demand rebound.

Table 6. West Coast (PADD 5) Percent Utilization of Operable Refinery Capacity.

Month	Capacity Utilized **in 2021**	Pre-COVID range for same month in 2010–2019 Minimum	Median	Maximum
January	73.3 %	76.4 %	83.7 %	90.1 %
February	74.2 %	78.2 %	82.6 %	90.9 %
March	81.2 %	76.9 %	84.8 %	95.7 %
April	82.6 %	77.5 %	82.7 %	91.3 %
May	84.2 %	76.1 %	84.0 %	87.5 %
June	88.3 %	84.3 %	87.2 %	98.4 %
July	85.9 %	83.3 %	90.7 %	97.2 %
August	87.8 %	79.6 %	90.2 %	98.3 %
September	—	80.4 %	87.2 %	96.9 %
October	—	76.4 %	86.1 %	91.2 %
November	—	77.6 %	85.3 %	94.3 %
December	—	79.5 %	87.5 %	94.4 %

Utilization of operable capacity in barrels/calendar day from Att. 17. PADD 5 includes AK, AZ, CA, HI, NV, OR, and WA. Pre-COVID data for the same month in 2010–2019 accounts for seasonal and interannual variability.

[78] CEC Fuel Watch (Att. 13).
[79] USEIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity. Appended hereto as Attachment 16.
[80] USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Inf. Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm Appended hereto as Attachment 17.

Spare California refining capacity during this period when fuels demand increased to reach pre-COVID levels and crude processing at the Marathon Martinez refinery was shut down (222,000 to 305,000 b/cd) exceeded the total 120,200 b/cd crude capacity of the Phillips 66 San Francisco Refinery.[81] The project would worsen this growing condition of overcapacity that drives refined fuels export emission-shifting by producing and selling even more California-targeted HEFA diesel into the California fuels market.

Accordingly, the project can be expected to worsen in-state petroleum refining overcapacity, and hence the emission shift, by adding a very large volume of HEFA diesel to the California liquid combustion fuels mix. Indeed, providing "renewable" fuels production for the California market is a project objective.[82] The DEIR, however, does not disclose or evaluate this causal factor for the observed emission-shifting impact of recent "renewable" diesel additions.

2.3 The DEIR Does Not Describe or Evaluate Project Design Specifications That Could Cause and Contribute to Significant Emission-shifting Impacts

Having failed to describe the unique capabilities and limitations of the proposed biofuel technology (§§ 1.1.1, 1.1.2), the DEIR does not evaluate how fully integrating renewable diesel into petroleum fuels refining, distribution, and combustion infrastructure could worsen emission shifting by more directly tethering biofuel addition here to petroleum fuel refining for export. Compounding its error, the DEIR does not evaluate the impact of another basic project design specification—project fuels production capacity. The DEIR does not estimate how much HEFA diesel the project could add to the existing statewide distillates production oversupply, or how much that could worsen the emission shifting impact. Had it done so, using readily available state default factors for the carbon intensities of these fuels, the County could have found that the project would likely cause and contribute to significant climate impacts. <u>*See*</u> Table 7 below.

Accounting for yields on feeds targeting renewable diesel[83] and typical feed and fuel densities shown in Table 7, operating at its 48,000 b/d the project could make approximately 1.62 million gallons per day of renewable diesel, resulting in export of the equivalent petroleum distillates

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[81] Though USEIA labels the San Francisco Refinery site as Rodeo, both the Rodeo Facility and the Santa Maria Facility capacities are included in the 120,200 barrels/calendar day (b/cd) cited: USEIA *Refinery Capacity by Individual Refinery* (Att. 16).
[82] DEIR p. 2-2.
[83] Pearlson et al., 2013. A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production. *Biofuels, Bioprod. Bioref.* 7: 89–96. DOI: 10.1002/bbb.1378. Appended hereto as Attachment 18.

volume. State default factors for full fuel chain "life cycle" emissions associated with the type of renewable diesel proposed account for a range of potential emissions, from lower emission ("residue") to higher emission ("crop biomass") feeds, which is shown in the table.[84]

The net emission shifting impact of the project based on this range of factors could thus be approximately 3.46 to 4.99 *million* metric tons (Mt) of CO_2e emitted per year. Table 7. Those potential project emissions would exceed the 10,000 metric tons per year (0.01 Mt/year) significance threshold in the DEIR by 345 to 498 times.

A *conservative* estimate of net cumulative emissions from this impact of the currently proposed biofuel refinery projects in the County, *if* state goals to replace all diesel fuels are achieved more quickly than anticipated, is in the range of approximately 74 Mt to 107 Mt over ten years. *Id.* .

Table 7. Potential GHG Emission Impacts from Project-induced Emission Shifting: Estimates Based on Low Carbon Fuel Standard Default Emission Factors.

RD: renewable diesel **PD:** petroleum distillate **CO_2e:** carbon dioxide equivalents **Mt:** million metric tons

Estimate Scope	Marathon Project	Phillips 66 Project	Both Projects
Fuel Shift (millions of gallons per day) [a]			
RD for in-state use	1.623	1.860	3.482
PD equivalent exported	1.623	1.860	3.482
Emission factor (kg CO_2e/galllon) [b]			
RD from residue biomass feedstock	5.834	5.834	5.834
RD from crop biomass feedstock	8.427	8.427	8.427
PD (petroleum distillate [ULSD factor])	13.508	13.508	13.508
Fuel-specific emissions (Mt/year) [c]			
RD from residue biomass feedstock	3.46	3.96	7.42
RD from crop biomass feedstock	4.99	5.72	10.7
PD (petroleum distillate)	8.00	9.17	17.2
Net emission shift impact [d]			
Annual minimum (Mt/year)	3.46	3.96	7.42
Annual maximum (Mt/year)	4.99	5.72	10.7
Ten-year minimum (Mt)	34.6	39.6	74.2
Ten-year maximum (Mt)	49.9	57.2	107

a. Calculated based on DEIR project feedstock processing capacities,* yield reported for refining targeting HEFA diesel by Pearlson et al., 2013, and feed and fuel specific gravities of 0.916 and 0.775 respectively. **b.** CARB default emission factors from tables 2, 4, 7-1, 8 and 9, Low Carbon Fuel Standard Regulation, CCR §§ 95484–95488. **c.** Fuel-specific emissions are the products of the fuel volumes and emission factors shown. **d.** The emission shift impact is the net emissions calculated as the sum of the fuel-specific emissions minus the incremental emission from the petroleum fuel *v.* the same volume of the biofuel. Net emissions are thus equivalent to emissions from the production and use of renewable diesel that *does not* replace petroleum distillates, as shown. Annual values compare with the DEIR significance threshold (0.01 Mt/year); ten-year values provide a conservative estimate of cumulative impact assuming expeditious implementation of State goals to replace all diesel fuels.
* Phillips 66 Project data calculated at 55,000 b/d feed rate, less than its proposed 80,000 b/d project feed capacity.

[84] Low Carbon Fuel Standard Regulation, tables 2, 4, 7-1, 8 and 9. CCR §§ 95484–95488.

2.4 The DEIR Does Not Consider Air Quality or Environmental Justice Impacts From GHG Co-Pollutants that Could Result from Project Emission Shifting

Having neglected to consider emission shifting that could result from the project, the DEIR does not evaluate air quality or environmental justice impacts that could result from GHG co-emissions. Had it considered the emission-shifting impact the County could have evaluated substantial relevant information regarding potential impacts of GHG co-pollutants.

Among other relevant available information: Pastor and colleagues found GHG co-pollutants from large industrial GHG emitters in general, and refineries in particular, caused substantially increased particulate matter emission burdens in low-income communities of color throughout the state.[85] Clark and colleagues found persistent disparately elevated exposures to refined fuels combustion emissions among people of color along major roadways in California and U.S.[86] Zhao and colleagues showed that exposures to the portion of those emissions that could result from climate protection decisions to use more biofuel, instead of more electrification of transportation among other sectors, would cause very large air pollution-induced premature death increments statewide.[87]

Again, however, the DEIR did not evaluate these potential project emission-shifting impacts.

CONCLUSION: A reasonable potential exists for the project to result in significant climate and air quality impacts by increasing the production and export of California-refined fuels instead of replacing petroleum fuels. This impact would be related to the particular type and use of biofuel proposed. Resultant greenhouse gases and co-pollutants would emit in California from excess petroleum and biofuel refining, and emit in California as well as in other states and nations from petroleum and biofuel feedstock extraction and end-use fuel combustion. The DEIR does not identify, evaluate, or mitigate these significant potential impacts of the project.

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[85] Pastor et al., 2010. *Minding the Climate Gap: What's at stake if California's climate law isn't done right and right away;* College of Natural Resources, Department of Environmental Science, Policy, and Management, University of California, Berkeley: Berkeley, CA; and Program for Environmental and Regional Equity, University of Southern California: Los Angeles, CA. Appended hereto as Attachment 19.
[86] Clark et al, 2017. Changes in transportation-related air pollution exposures by race-ethnicity and socioeconomic status: Outdoor nitrogen dioxide in the United States in 2000 and 2010. *Environmental Health Perspectives* 097012-1 to 097012-10. 10.1289/EHP959. Appended hereto as Attachment 20.
[87] Zhao et al., 2019. Air quality and health co-benefits of different deep decarbonization pathways in California. *Environ. Sci. Technol.* 53: 7163–7171. DOI: 10.1021/acs.est.9b02385. Appended hereto as Attachment 21.

3. THE DEIR DOES NOT PROVIDE A COMPLETE OR ACCURATE ANALYSIS OF PROCESS HAZARDS AND DOES NOT IDENTIFY, EVALUATE, OR MITIGATE SIGNIFICANT POTENTIAL PROJECT HAZARD IMPACTS

Oil refining is an exceptionally high-hazard industry in which switching to a new and different type of oil feed has known potential to introduce new hazards, intensify existing hazards, or both. Switching from crude petroleum to HEFA feedstock refining introduces specific new hazards that could increase the incidence rate of refinery explosions and uncontrolled fires, hence the likelihood of potentially catastrophic consequences of the project over its operational duration. The DEIR does not identify, evaluate, or mitigate these specific process hazards or significant potential process hazard impacts. A series of errors and omissions in the DEIR further obscures these process hazards and impacts.

3.1 The DEIR Does Not Provide a Complete or Accurate Analysis of Project Hazards

The DEIR does not include, and does not report substantively on results from, any of several standard process hazard analysis requirements applicable to petroleum crude refining. It does not include or report substantive results of any Process Hazard Analysis (PHA),[88] Management of Change analysis, Hierarchy of Hazard Controls Analysis, Inherent Safety Measure, or written recommendations to prioritize inherent safety measures and then include safeguards as added layers of protection[89] from any potential project process hazard. Instead the DEIR concludes that project refining hazard impacts will be less than significant[90] based on a series of unsupported and incomplete or inaccurate assertions.

3.1.1 Incomplete and inaccurate evaluation of process material explosion and fire hazard

The DEIR seeks to quantify combustible and flammable material hazards from whole feedstocks but does not evaluate explosion or fire hazards associated with conversion of feedstocks in the refinery. This incomplete evaluation contributes to the inaccurate DEIR impact conclusion. HEFA feeds are converted to hydrocarbon gases which may be indistinguishable, in terms of explosivity, combustibility or flammability, from petroleum products in process reactors operating at high temperatures and extreme pressures, and this occurs at greater hydrogen concentrations than those conditions in petroleum refining. §§ 1.2.1–1.2.3.

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[88] A PHA is a hazard evaluation to identify, evaluate, and control the hazards involved in a process.
[89] *See* California refinery process safety management regulation, CCR § 5189.
[90] DEIR pp. 3.9-17, 3.9-18.

3.1.2 Unsupported and inaccurate comparison of project refining to petroleum refining

The DEIR assumes project processing will be "similar" to historic crude processing at the refinery to conclude that reduced feedstock throughput volumes and fewer operating process units[91] will reduce project process hazards. Its conclusion incorrectly equates the hazards of different types of equipment and process reactions without factual support. Available data it ignores suggest the types of process units to be repurposed experience hazard incidents more often than many other types of petroleum refining units, and show that switching to HEFA feeds could further increase process hazards in the repurposed equipment, as discussed in § 3.2 below.

3.1.3 Unsupported and incomplete evaluation of applicable process hazard control mandates

The DEIR concludes "continued compliance" with multiple "federal, state and local regulations and proper operation and maintenance of equipment" will ensure that process hazard impacts "would be less than significant."[92] However, the DEIR does not specify which provisions of existing process safety regulations and requirements applicable to petroleum refining might no longer be applicable to the proposed project biomass refining. The DEIR thus omits discussion of whether the project will be exempt from requirements to fully analyze and prioritize inherent safety measures—the essential, and most effective type, of process hazard protection, which is designed to eliminate specified hazards.[93] These omissions render its conclusion unsupported.

3.1.4 Incomplete and inaccurate evaluation of existing and available hazard control measures

The DEIR provides an incomplete and inaccurate review of available process safety measures. It gives only cursory mention to safeguards[94] such as equipment maintenance, contingency plans, and a safety plan to be updated for the project.[95] Then, it does not disclose that safeguards are relatively ineffective safety measures, or that crude refining safety standards require analysis of specific hazards to prioritize inherent safety measures because of this problem with safeguards.[96] Omitting the requirement to prioritize inherent safety measures in combination with safeguards[97] further obscures the need for evaluation of *specific* process hazards, which the DEIR omits.

[91] DEIR p. 3.9-17; DEIR Appendix-HAZ pp. 23, 25.
[92] DEIR pp. 3.9-17, 3.9-18; DEIR Appendix-HAZ p. 27.
[93] California refinery process safety management regulation, CCR § 5189.
[94] Surprisingly, nowhere in its 456 pages does Volume I of the DEIR discuss flares, one of the most frequently needed emergency safeguards against escalating hazards in process units to be repurposed by the project.
[95] DEIR Appendix-HAZ pp. 25, 27; DEIR pp. 3.9-17, 3.9-18.
[96] California refinery process safety management regulation, CCR § 5189.
[97] *Id.*

3.1.5 Improper reliance on unspecified future process hazard mitigation measures

The DEIR conclusion that there would be no significant process hazard to mitigate[98] is based on unspecified future hazard mitigation. "The facility's plan would be updated to reflect the changes in operations associated with the proposed Project. ... Update of the facility's current Safety Plan (Injury and Illness Prevention Program [Marathon 2020]) to reflect changed conditions ... would assist in reducing hazards of explosive or otherwise hazardous materials."[99]

In fact, the less-than-significant hazard conclusion in the DEIR assumes future actions to address hazards of project changes in refining—actions to be specified in plans to address those project changes which, it says, have not yet been developed. However, inherently safer measures which may be feasible to introduce during project design, review, and construction may no longer be feasible after the project is approved or built.[100] The DEIR does not identify or evaluate this potential for deferring hazard mitigation analysis to foreclose mitigation.

3.2 The DEIR Does Not Identify or Evaluate Significant Process Hazard Impacts, Including Refinery Explosions and Fires, That Could Result from the Project

Had the DEIR provided a complete and accurate process hazard evaluation the County could have identified significant impacts that would result from project process hazards.[101]

3.2.1 The DEIR does not disclose or evaluate available information which reveals that the project could increase refinery explosion and fire risks compared with crude refining

After a catastrophic pipe failure ignited in the Richmond refinery sending 15,000 people to hospital emergency rooms, a feed change was found to be a causal factor in that disaster—and failures by Chevron and public safety officials to take hazards of that feed change seriously were found to be its root causes. The oil industry knew that introducing a new and different crude into an existing refinery can introduce new hazards. More than this, as it has long known, side effects of feed processing can cause hazardous conditions in the same types of hydro-conversion units now proposed to be repurposed for HEFA biomass feeds, and feedstock changes are among the most frequent causes of dangerous upsets in these hydro-conversion reactors.[102]

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[98] DEIR pp. 3.9-18, 3.9-19,
[99] *Id.*
[100] CSB, 2013 (Att. 7).
[101] My recent work has included in-depth review and analysis of process hazards associated with crude-to-biofuel refinery conversions; summaries of this work are excerpted from Karras, 2021a (Att. 2) in §§ 3.2.1–3.2.5 herein.
[102] Karras, 2021a (Att. 2).

Differences between the new biomass feedstock proposed and crude oil are more extreme than those among crudes which Chevron ignored the hazards of before its August 2012 fire in Richmond, and involve oxygen in the feed, rather than sulfur as in that disaster. This categorical difference between oxygen and sulfur, rather than a degree of difference in feed sulfur content, risks further minimizing the accuracy, or even feasibility, of predictions based on historical data. At 10.8–11.5 wt. %, HEFA feeds have very high oxygen content, while the petroleum crude fed to refinery processing has virtually none.[103] Carbonic acid forms from that oxygen in HEFA processing.[104] Carbonic acid corrosion is a known hazard in HEFA processing.[105] But this corrosion mechanism, and the specific locations it attacks in the refinery, differ from those of the sulfidic corrosion involved in the 2012 Richmond incident. Six decades of industry experience with sulfidic corrosion cannot reliably guide—and could misguide—the refiner as it attempts to find, then fix, damage from this new hazard before it causes equipment failures.[106]

Worse, high-oxygen HEFA feedstock can boost hydrogen consumption in hydro-conversion reactors dramatically. That creates more heat in reactors already prone to overheating in petroleum refining. Switching repurposed hydrocrackers and hydrotreaters to HEFA feeds would introduce this second new oxygen-related hazard.[107]

A specific feedback mechanism underlies this hazard. The hydro-conversion reactions are exothermic: they generate heat.[108] [109] [110] When they consume more hydrogen, they generate more heat.[111] Then they get hotter, and crack more of their feed, consuming even more hydrogen,[112] [113] so “the hotter they get, the faster they get hot.”[114] And the reactions proceed at

[103] *Id.*
[104] Chan, 2020. *Converting a Petroleum Diesel Refinery for Renewable Diesel;* White Paper / Renewable Diesel. Burns McDonnell. www.burnsmcd.com. Appended hereto as Attachment 22.
[105] *Id.*
[106] Karras, 2021a (Att. 2).
[107] *Id.*
[108] Robinson and Dolbear, 2007. Commercial Hydrotreating and Hydrocracking. *In:* Hydroprocessing of heavy oils and residua. Ancheyta, J., and Speight, J., eds. CRC Press, Taylor & Francis Group: Boca Raton, FL. ISBN-13: 978-0-8493-7419-7. Appended hereto as Attachment 23.
[109] van Dyk et al., 2019. Potential synergies of drop-in biofuel production with further co-processing at oil refineries. *Biofuels Bioproducts & Biorefining* 13: 760–775. DOI: 10.1002/bbb.1974. Appended hereto as Attachment 24.
[110] Chan, 2020 (Att. 22).
[111] van Dyk et al., 2019 (Att. 24).
[112] *Id.*
[113] Robinson and Dolbear, 2007 (Att. 23).
[114] *Id.*

extreme pressures of 600–2,800 pound-force per square inch,[115] so the exponential temperature rise can happen fast.

Refiners call these runaway reactions, temperature runaways, or "runaways" for short. Hydro-conversion runaways are remarkably dangerous. They have melted holes in eight-inch-thick, stainless steel, walls of hydrocracker reactors,[116] and worse. Consuming more hydrogen per barrel in the reactors, and thereby increasing reaction temperatures, HEFA feedstock processing can be expected to increase the frequency and magnitude of runaways.[117]

High temperature hydrogen attack or embrittlement of metals in refining equipment with the addition of so much more hydrogen to HEFA processing is a third known hazard.[118] And given the short track record of HEFA processing, the potential for other, yet-to-manifest, hazards cannot be discounted.[119]

On top of all this, interdependence across the process system—such as the critical need for real-time balance between hydro-conversion units that feed hydrogen and hydrogen production units that make it—magnifies these hazards. Upsets in one part of the system can escalate across the refinery. Hydrogen-related hazards that manifest at first as isolated incidents can escalate with catastrophic consequences.[120]

3.2.2 <u>The DEIR does not disclose or evaluate available information about potential consequences of hydrogen-related hazards that the project could worsen</u>

Significant and sometimes catastrophic incidents involving the types of hydrogen processing proposed by the project are unfortunately common in crude oil refining, as reflected in the following incident briefs posted by *Process Safety Integrity*[121] report:

- Eight workers are injured and a nearby town is evacuated in a 2018 hydrotreater reactor rupture, explosion and fire.
- A worker is seriously injured in a 2017 hydrotreater fire that burns for two days and causes an estimated $220 million in property damage.

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[115] *Id.*
[116] *Id.*
[117] Karras, 2021a (Att 2).
[118] Chan, 2020 (Att. 22).
[119] Karras, 2021a (Att. 2).
[120] *Id.*
[121] Process Safety Integrity *Refining Incidents;* accessed Feb–Mar 2021; available for download at: https://processsafetyintegrity.com/incidents/industry/refining. Appended hereto as Attachment 25.

- A reactor hydrogen leak ignites in a 2017 hydrocracker fire that causes extensive damage to the main reactor.
- A 2015 hydrogen conduit explosion throws workers against a steel refinery structure.
- Fifteen workers die, and 180 others are injured, in a series of explosions when hydrocarbons flood a distillation tower during a 2005 isomerization unit restart.
- A vapor release from a valve bonnet failure in a high-pressure hydrocracker section ignites in a major 1999 explosion and fire at the Chevron Richmond refinery.
- A worker dies, 46 others are injured, and the community must shelter in place when a release of hydrogen and hydrocarbons under high temperature and pressure ignites in a 1997 hydrocracker explosion and fire at this Martinez refinery, then owned by Tosco.
- A Los Angeles refinery hydrogen processing unit pipe rupture releases hydrogen and hydrocarbons that ignite in a 1992 explosion and fires that burn for three days.
- A high-pressure hydrogen line fails in a 1989 fire which buckles the seven-inch-thick steel of a hydrocracker reactor that falls on other nearby Richmond refinery equipment.
- An undetected vessel overpressure causes a 1987 hydrocracker explosion and fire.

These incidents all occurred in the context of crude oil refining. For the reasons described in this section, there is cause for concern that the frequency and severity of these types of hydrogen-related incidents could increase with HEFA processing.

3.2.3 <u>The DEIR does not disclose or evaluate the limited effectiveness of current and proposed safeguards against hydrogen-related hazards that the project could worsen</u>

Refiners have the ability to use extra hydrogen to quench, control, and guard against runaway reactions, a measure which has proved partially effective and appears necessary for hydro-conversion processing to remain profitable. As a safety measure, however, it has proved ineffective so often that hydro-conversion reactors are equipped to depressurize rapidly to flares.[122] [123] And that last-ditch safeguard, too, has repeatedly failed to prevent catastrophic incidents. The Richmond and Martinez refineries were equipped to depressurize to flares, for example, during the 1989, 1997, 1999 and 2012 incidents described above.[124]

3.2.4 <u>The DEIR does not disclose or evaluate available site-specific data informing the frequency with which hydrogen-related hazards of the project could manifest</u>

In fact, precisely because it is a last-ditch safeguard, to be used only when all else fails, flaring reveals how frequently these hazards manifest as potentially catastrophic incidents. Despite

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[122] Robinson and Dolbear, 2007 (Att. 23).
[123] Chan, 2020 (Att. 22).
[124] Karras, 2021a (Att. 2).

current safeguards, hydro-conversion and hydrogen-related process safety hazards which their HEFA conversion projects could worsen contribute to significant flaring incidents at the Marathon Martinez and Phillips 66 refineries frequently.

Table 8 summarizes specific examples of causal analysis reports for significant flaring which show that hydrogen-related hazard incidents occurred at the refineries a combined total of 100 times from January 2010 through December 2020. This is a conservative estimate, since incidents can cause significant impact without causing environmentally significant flaring. Nevertheless, it represents, on average, and accounting for the Marathon plant closure since 28 April 2020, a hydrogen-related incident frequency at one of these refineries every 39 days.[125]

Sudden unplanned or emergency shutdowns of major hydro-conversion or hydrogen production plants occurred in 84 of these 100 reported process safety hazard incidents.[126] Such sudden forced shutdowns of *both* hydro-conversion and hydrogen production plants occurred in 22 of these incidents.[127] In other words, incidents escalated to refinery-level systems involving multiple plants frequently—a foreseeable consequence, given that both hydro-conversion and hydrogen production plants are susceptible to upset when the critical balance of hydrogen production supply and hydrogen demand between them is disrupted suddenly. In four of these incidents, consequences of underlying hazards included fires in the refinery.[128]

3.2.5 <u>The DEIR did not identify significant hydrogen-related process hazard impacts that could result from the project</u>

Since switching to HEFA refining is likely to further increase the frequency and magnitude of these already-frequent significant process hazard incidents, and flaring has proven unable to prevent every incident from escalating to catastrophic proportions, catastrophic consequences of HEFA process hazards are foreseeable.[129] The DEIR did not identify, evaluate, or mitigate these significant potential impacts of the project.

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[125] *Id.*; and BAAQMD *Causal Analysis Reports for Significant Flaring;* Bay Area Air Quality Management District: San Francisco, CA. Reports submitted by Marathon and formers owners of the Marathon Martinez Refinery, and submitted by Phillips and former owners of the Phillips 66 San Francisco Refinery at Rodeo, pursuant to BAAQMD Regulation 12-12-406. Appended hereto as Attachment 26.
[126] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[127] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[128] Karras, 2021a (Att. 2); BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[129] Karras, 2021a (2021).

Table 8. Examples from 100 hydrogen-related process hazard incidents at the Phillips 66 Rodeo and Marathon Martinez refineries, 2010–2020.

Date [a]	Refinery	Hydrogen-related causal factors reported by the refiner [a]
3/11/10	Rodeo	A high-level safety alarm during a change in oil feed shuts down Unit 240 hydrocracker hydrogen recycle compressor 2G-202, forcing the sudden shutdown of the hydrocracker
5/13/10	Martinez	A hydrotreater charge pump bearing failure and fire forces #3 HDS hydrotreater shutdown [b]
9/28/10	Martinez	A hydrocracker charge pump trip leads to a high temperature excursion in hydrocracker reactor catalyst beds that forces sudden unplanned hydrocracker shutdown [c]
2/17/11	Martinez	A hydrogen plant fire caused by process upset after a feed compressor motor short forces the hydrogen plant shutdown; the hydrocracker shuts down on sudden loss of hydrogen
9/10/12	Rodeo	Emergency venting of hydrogen to the air from one hydrogen plant to relieve a hydrogen overpressure as another hydrogen plant starts up ignites in a refinery hydrogen fire
10/4/12	Rodeo	A hydrocracker feed cut due to a hydrogen makeup compressor malfunction exacerbates a reactor bed temperature hot spot, forcing a sudden hydrocracker shutdown [d]
1/11/13	Martinez	Cracked, overheated and "glowing" hydrogen piping forces an emergency hydrogen plant shutdown; the loss of hydrogen forces hydrocracker and hydrotreater shutdowns
4/17/15	Martinez	Cooling pumps trip, tripping the 3HDS hydrogen recycle compressor and forcing a sudden shutdown of the hydrotreater as a safety valve release cloud catches fire in this incident [e]
5/18/15	Rodeo	A hydrocracker hydrogen quench valve failure forces a sudden hydrocracker shutdown [f]
5/19/15	Martinez	A level valve failure, valve leak and fire result in an emergency hydrotreater shutdown
3/12/16	Rodeo	A Unit 240 level controller malfunction trips off hydrogen recycle compressor G-202, which forces an immediate hydrocracker shutdown to control a runaway reaction hazard [g]
1/22/17	Martinez	An emergency valve malfunction trips its charge pump, forcing a hydrocracker shutdown
5/16/19	Martinez	A recycle compressor shutdown to fix a failed seal valve forces a hydrocracker shutdown [h]
6/18/19	Martinez	A control malfunction rapidly depressurized hydrogen plant pressure swing absorbers
11/11/19	Rodeo	A failed valve spring shuts down hydrogen plant pressure swing absorbers in a hydrogen plant upset; the resultant loss of hydrogen forces a sudden hydrotreater shutdown [i]
2/7/20	Martinez	An unprotected oil pump switch trips a recycle compressor, shutting down a hydrotreater
3/5/20	Rodeo	An offsite ground fault causes a power sag that trips hydrogen make-up compressors, forcing the sudden shutdown of the U246 hydrocracker [j]
10/16/20	Rodeo	A pressure swing absorber valve malfunction shuts down a hydrogen plant; the emergency loss of hydrogen condition results in multiple process unit upsets and shutdowns [k]

a. Starting date of the environmentally significant flaring incident, as defined by Bay Area Air Quality Management District Regulations § 12-12-406, which requires causal analysis by refiners that is summarized in this table. An incident often results in flaring for more than one day. The 100 "unplanned" hydro-conversion flaring incidents these examples illustrate are provided in Attachment 26 (*see* Att. 2 for list). Notes b–k below further describe some of these examples with quotes from refiner causal reports. **b.** "Flaring was the result of an 'emergency' ... the #3 HDS charge pump motor caught fire ... ." **c.** "One of the reactor beds went 50 degrees above normal with this hotter recycle gas, which automatically triggered the 300 lb/minute emergency depressuring system." **d.** "The reduction in feed rates exacerbated an existing temperature gradient ...higher temperature gradient in D-203 catalyst Bed 4 and Bed 5 ... triggered ... shutdown of Unit 240 Plant 2."
e. "Flaring was the result of an Emergency. 3HDS had to be shutdown in order to control temperatures within the unit as cooling water flow failed." **f.** "Because hydrocracking is an exothermic process ... [t]o limit temperature rise... [c]old hydrogen quench is injected into the inlet of the intermediate catalyst beds to maintain control of the cracking reaction."
g. "Because G-202 provides hydrogen quench gas which prevents runaway reactions in the hydrocracking reactor, shutdown of G-202 causes an automatic depressuring of the Unit 240 Plant 2 reactor ... ." **h.** "Operations shutdown the Hydrocracker as quickly and safely as possible." **i.** "[L]oss of hydrogen led to the shutdown of the Unit 250 Diesel Hydrotreater." **j.** "U246 shut down due to the loss of the G-803 A/B Hydrogen Make-Up compressors."
k. "Refinery Emergency Operating Procedure (REOP)-21 'Emergency Loss of Hydrogen' was implemented."

3.2.6 <u>The DEIR did not identify or evaluate the potential for deferred mitigation of process hazards to foreclose currently feasible hazard prevention measures</u>

As the U.S. Chemical Safety Board found in its investigation of the 2012 Richmond refinery fire: "It is simpler, less expensive, and more effective to introduce inherently safer features during the design process of a facility rather than after the process is already operating. Process upgrades, rebuilds, and repairs are additional opportunities to implement inherent safety concepts."[130] Thus, licensing or building the project without first specifying inherently safer features to be built into it has the potential to render currently feasible mitigation measures infeasible at a later date. The DEIR does not address this potential. Examples of specific inherently safer measures which the DEIR could have but did not identify or analyze as mitigation for project hazard impacts include, but are not limited to, the following:

Feedstock processing hazard condition. The County could adopt a project condition to forgo or minimize the use of particularly high process hydrogen demand feedstocks. Since increased process hydrogen demand would be a causal factor for the significant process hazard impacts (§§ 3.2.1–3.2.5) and some HEFA feedstocks increase process hydrogen demand significantly more than other others (§§ 1.2.2, 1.3.1), avoiding feedstocks with that more hazardous processing characteristic would lessen or avoid the hazard impact.

Product slate processing hazard condition. The County could adopt a project condition to forgo or minimize particularly high-process hydrogen demand product slates. Minimizing or avoiding HEFA refining to boost jet fuel yield, which significantly increases hydrogen demand (§§ 1.2.1, 1.2.2), would thereby lessen or avoid further intensified hydrogen reaction hazard impacts.

Hydrogen input processing hazard condition. The County could adopt a project condition to limit hydrogen input per barrel, which could lessen or avoid the process hazard impacts from particularly high-process hydrogen demand feedstocks, product slates, or both.

Hydrogen backup storage processing hazard condition. The County could adopt a project condition to store hydrogen onsite for emergency backup use. This would lessen or avoid hydro-conversion plant incident impacts caused by the sudden loss of hydrogen inputs when hydrogen plants malfunction, a significant factor in escalating incidents as discussed in §§ 3.2.1 and 3.2.4.

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[130] CSB, 2013 (Att. 7).

Rather than suggesting how or whether the subject project hazard impact could adequately be mitigated, the examples illustrate that the DEIR could have analyzed mitigation measures that are feasible now, and whether deferring those measures might render them infeasible later.

CONCLUSION: There is a reasonable potential for the proposed changes in refinery feedstock processing to result in specific hazard impacts involving hydro-conversion processing, including explosion and uncontrolled refinery fire, in excess of those associated with historic petroleum crude refining operations. The DEIR did not identify, evaluate, or mitigate these significant process hazard impacts that could result from the project.

4. AIR QUALITY AND HAZARD RELEASE IMPACTS OF PROJECT FLARING THAT AVAILABLE EVIDENCE INDICATES WOULD BE SIGNIFICANT ARE NOT IDENTIFIED, EVALUATED, OR MITIGATED IN THE DEIR

For the reasons discussed above, the project would introduce new hazards that can be expected to result in new hazard incidents that involve significant flaring, and would be likely increase the frequency of significant flaring. Based on additional available evidence, the episodic releases of hazardous materials from flares would result in acute exposures to air pollutants and significant impacts. The DEIR does not evaluate the project flaring impacts or their potential significance and commits a fundamental error which obscures these impacts.

4.1 The DEIR Did Not Evaluate Environmental Impacts of Project Flaring

Use of refinery flare systems—equipment to rapidly depressurize process vessels and pipe their contents to uncontrolled open-air combustion in flares—is included in the project.[131] The DEIR reports this,[132] and identifies a flare maintenance turnaround during 2018.[133] However, the DEIR does not discuss potential environmental impacts of project flaring anywhere in its 456 pages. The DEIR does not disclose or mention readily available data showing frequently recurrent significant flaring at the refinery that is documented and discussed in §3.2.4 above, or any other site-specific flare impact data. This represents an enormous gap in its environmental analysis.

[131] DEIR pp. 2-22, 3.3-1, Figure 2-9.
[132] DEIR pp. 2-22, 3.3-1, Figure 2-9.
[133] DEIR p. 3-5, Table 3-5.

4.2 The DEIR Did Not Identify, Evaluate, or Mitigate Significant Potential Flare Impacts That Could Result from the Project

Had the DEIR assessed available flare frequency, magnitude and causal factors data, the County could have found that project flaring impacts would be significant, as discussed below.

4.2.1 <u>The DEIR did not consider incidence data that indicate the potential for significant project flaring impacts</u>

Flaring emits a mix of many toxic and smog forming air pollutants—particulate matter, hydrocarbons ranging from polycyclic aromatics to methane, sulfur dioxide, hydrogen sulfide, and others—from partially burning off enormous gas flows. Most of the 100 significant flaring incidents documented and described in subsection 3.2.4 above flared more than two million standard cubic feet (SCF) of vent gas each, and many flared more than ten million SCF.[134] The plumes cross into surrounding communities, where people experience acute exposures to flared pollutants repeatedly, at levels of severity and at specific locations which vary with the specifics of the incident and atmospheric conditions at the time when flaring recurs.

In 2005, flaring was linked to episodically elevated localized air pollution by analyses of a continuous, flare activity-paired, four-year series of hourly measurements in the ambient air near the fence lines of four Bay Area refineries.[135] By 2006, the regional air quality management district independently confirmed the link, assessed community-level impacts, and set environmental significance thresholds for refinery flares.[136] [137] These same significance thresholds were used to require Marathon and Phillips 66 to report the flare incident data described in subsection 3.2.4 and in this subsection above.[138] [139]

Thus, each of the hundred hydrogen-related flaring incidents since 2010 at the Marathon Martinez and Phillips 66 Rodeo refineries *individually* exceeded a relevant significance threshold

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[134] Karras, 2021a (Att. 2).
[135] Karras and Hernandez, 2005. *Flaring Hot Spots: Assessment of episodic local air pollution associated with oil refinery flaring using sulfur as a tracer;* Communities for a Better Environment: Oakland and Huntington Park, CA. Appended hereto at Attachment 27.
[136] Ezersky, 2006. *Staff Report: Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* 3 March 2006. Planning and Research Division, Bay Area Air Quality Management District: San Francisco, CA. <u>*See*</u> *esp.* pp. 5–8, 13, 14. Appended hereto as Attachment 28.
[137] BAAQMD Regulations, § 12-12-406. Bay Area Air Quality Management District: San Francisco, CA. <u>*See*</u> Regulation 12, Rule 12, at: https://www.baaqmd.gov/rules-and-compliance/current-rules
[138] *Id.*
[139] BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).

for air quality. New hazard incidents, and hence flare incidents, can be expected to result from repurposing the same process units that flared without removing the underlying causes for that flaring,[140] which is what implementing the project would do. Consequently, the proposed project can be expected to result in significant episodic air pollution impacts.

4.2.2 The DEIR did not consider causal evidence that indicates project flare incident rates have the potential to exceed those of historic petroleum crude refining

Further, the project would do more than repurpose the same process units that flare without removing the underlying causes for that flaring. The project would switch to new and very different feeds with new corrosion and mechanical integrity hazards, new chemical hydrogen demands and extremes in reaction heat runaways, in processes and systems prone to potentially severe damage from these very causal mechanisms; damage it would attempt to avoid by flaring. See Section 3. It is thus reasonably likely that compared with historic crude refining, the new HEFA process hazards might more frequently manifest in refinery incidents (*Id.*), hence flaring.

4.2.3 The DEIR did not assess flare impact frequency, magnitude, or causal factors

As stated, the DEIR does not discuss potential environmental impacts of project flaring. It does not disclose, discuss, evaluate or otherwise address any of the readily available data, evidence or information described in this subsection (§ 4.2).

4.3 An Exposure Assessment Error in the DEIR Invalidates its Impact Conclusion and Obscures Project Flare Impacts

A fundamental error in the DEIR obscures flare impacts. The DEIR ignores acute exposures to air pollution from episodic releases entirely to conclude that air quality impacts from project refining would not be significant based only on long-term annual averages of emissions.[141] The danger in the error may best be illustrated by example: The same mass of hydrogen sulfide emission into the air that people nearby breathe without perceiving even its noxious odor when it is emitted continuously over a year can kill people *in five minutes* when that “annual average” emits all at once in an episodic release.[142] Acute and chronic exposure impacts differ.

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[140] See Section 3 herein; Karras, 2021a (Att. 2).

[141] DEIR pp. 3.3-14 to 3.3-16, 3.3-25 to 3.3-40, Appendix AQ_GHG. See also DEIR pp. 3-3 to 3-6.

[142] Based on H_2S inhalation thresholds of 0.025–8.00 parts per million for perceptible odor and 1,000–2,000 ppm for respiratory paralysis followed by coma and death within seconds to minutes of exposure. See Sigma-Aldrich, 2021. *Safety Data Sheet: Hydrogen Sulfide;* Merck KGaA: Darmstadt, DE. Appended hereto as Attachment 29.

4.3.1 The DEIR air quality analysis failed to consider the environmental setting of the project

An episodic refinery release can cause locally elevated ambient air pollution for hours or days with little or no effect on refinery emissions averaged over the year. At the same time, people in the plume released cannot hold their breath more than minutes and can experience toxicity due to inhalation exposure. In concluding the project would cause no significant air quality impact without considering impacts from acute exposures to episodic releases, the DEIR failed to properly consider these crucial features of the project environmental setting.

4.3.2 The DEIR air quality analysis failed to consider toxicological principles and practices

The vital need to consider both exposure concentration and exposure duration has been a point of consensus among industrial and environmental toxicologists for decades. This consensus has supported, for example, the different criteria pollutant concentrations associated with a range of exposure durations from 1-hour to 1-year in air quality standards that the DEIR itself reports.[143] Rather than providing any factual support for concluding impacts are not significant based on analysis that excludes acute exposures to episodic releases, the science conclusively rebuts that analytical error in the DEIR.

4.3.3 The DEIR air quality analysis failed to consider authoritative findings and standards that indicate project flaring would exceed a community air quality impact threshold

Crucially, the Bay Area Air Quality Management District adopted the significance threshold for flaring discussed above based on *one-hour* measurements and modeling of flare plumes, which, it found, "show an impact on the nearby community."[144] On this basis the District further found that its action to adopt that significance threshold "will lessen the emissions impact of flaring on those who live and work within affected areas."[145] Thus the factual basis for finding flaring impacts significant is precisely the evidence that the DEIR ignores in wrongly concluding that project refining impacts on air quality are not significant.

CONCLUSION: The project is likely to result in a significant air quality impact associated with flaring, and has reasonable potential to worsen this impact compared with historic petroleum

[143] DEIR p. 3.3-8; Table 3.3-2.
[144] Ezersky, 2006 (Att. 28).
[145] *Id.*

crude refining operations at the site. The DEIR does not identify, evaluate, or analyze measures to lessen or avoid this significant potential impact.

5. THE DEIR OBSCURES THE SIGNIFICANCE OF PROJECT IMPACTS BY ASSERTING AN INFLATED FUTURE BASELINE WITHOUT FACTUAL SUPPORT

The baseline condition for comparison with project impacts includes the existing petroleum storage and transfer operation at the project site. The DEIR, however, compares project impacts with those of a petroleum refinery with crude feed capacity more than three times the biomass feed capacity of the proposed project. It argues for this "future baseline" by stating such a crude refinery operated and was permitted to operate at the site historically, but provides no factual support for speculating that those historic conditions will become future conditions at the site. The DEIR does not disclose or evaluate evidence which strongly suggests that a future return to historic crude refining at the site is unlikely. As a result of these errors the DEIR inflates the project baseline and systematically understates the significance of project impacts.

5.1 The DEIR Does Not Describe Existing Baseline Conditions That Suggest its Conclusion Linking Project and Onsite Crude Refining Outcomes is Unfounded

5.1.1 Petroleum storage and transfer rather than refining is the existing project site condition

From before the project was proposed until now, the existing primary use of the proposed project site has been and is for petroleum storage and transfer operations.[146] The DEIR, however, concludes that the project baseline is petroleum crude refining at historic rates.[147] The project baseline asserted by and applied in the DEIR does not represent existing conditions.

5.1.2 Petroleum crude refining at the site has been shuttered with no plans to restart

Marathon shuttered crude refining operations at the refinery on 28 April 2020.[148] In July 2020, Marathon asserted that closure was permanent with no plans to restart the refinery.[149] The DEIR

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[146] *See* DEIR p. 2-22; Table 2-1 (existing petroleum storage for distribution to be maintained).
[147] DEIR pp. 3-3 through 3-7.
[148] April 28, 2020 Flare Event Causal Analysis for Tesoro Refining and Marketing Company, subsidiary of Marathon Petroleum, Martinez Refinery Plant #B2758, submitted to the Bay Area Air Quality Management District dated June 29, 2020. Accessed from www.baaqmd.gov/about-air-quality/research-and-data/flare-data/flare-causal-reports. *See* BAAQMD *Causal Analysis Reports for Significant Flaring* (Att. 26).
[149] BAAQMD, 2021. Workshop Report, Draft Amendments to Regulation 6, Rule 5: Particulate Emissions from Petroleum Refinery Fluidized Catalytic Cracking Units. January 2021. Bay Area Air Quality Management District: San Francisco, CA. *See* p. 14 FN; captions of tables 1, 2, 6, 8–10.

contradicts this public assertion by the project proponent without identifying, evaluating, or otherwise addressing the contradiction.

5.1.3 The project launched after crude refining ceased permanently at the site

Marathon was "evaluating the possibility" of this project in August 2020,[150] began "detailed engineering" for the project during October–December 2020,[151] and "approved these plans" on February 24, 2021.[152] All of that occurred after the April 2020 crude refining closure and July 2020 announcement that closure was permanent, but the DEIR does not disclose or address this evidence that decisions by the refiner regarding onsite crude refining predated and were not linked to decisions about the project. In addition, the DEIR does not discuss or explain the discrepancy between the Project Description, which does not propose restarting crude refining as an alternative to the project, and the opposite assumption in its baseline analysis.

5.2 The DEIR Does Not Disclose or Evaluate Available Evidence that Future Restart of Onsite Crude Refining is Unlikely due to Factors Independent from the Project

Converging lines of evidence which the DEIR does not disclose or evaluate strongly suggest that the shuttered crude refinery is unlikely to restart whether or not the project proceeds.

5.2.1 Available evidence indicates that the crude refinery closed during a refining assets consolidation that proceeded before, and independently from, plans for the project

Available evidence indicates that the refinery closed as part of a consolidation of refining assets. Refining assets follow the rule of returns to scale. Over time, smaller refineries expand or close.[153] Consolidation, in which fewer refineries build to greater capacity, has been the trend for decades across the U.S.[154] The increase in total capacity concentrated in fewer plants[155] further reveals returns to scale as a factor in this consolidation. Access to markets also is a factor. The domestic market for engine fuels refined here is primarily in California and limited

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[150] August 25, 2020 email from A. Petroske, Marathon, to L. Guerrero and N. Torres, Contra Costa County.
[151] US Securities and Exchange Commission Form 10-K, Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 for the fiscal year ended December 31, 2020, by Marathon Petroleum Corporation. Accessed from https://www.marathonpetroleum.com/Investors/ *See* p. 50.
[152] *Id.*
[153] Meyer, D.W., and Taylor, C.T. The Determinants of Plant Exit: The Evolution of the U.S. Refining Industry. Working Paper No 328, November 2015. Bureau of Economics, Federal Trade Commission: Washington, D.C. https://www.ftc.gov/system/files/documents/reports/determinants-plant-exit-evolution-u.s.refining-industry/wp328.pdf
[154] *Id.*
[155] *Id.*

almost entirely to the West Coast.[156] [157] Tesoro, Andeavor, and Marathon expanded refining capacity elsewhere in this market instead of at the Martinez Refinery—investment decisions that created the largest refinery on the West Coast in Los Angeles[158] and left Marathon with *extra* capacity in California, and across the West Coast, even after its Martinez crude refinery closed. See Table 9.

Table 9. Total Operable Atmospheric Crude Distillation Capacity of West Coast Refineries Owned by Marathon Petroleum Corp. / Andeavor / Tesoro Refining and Marketing, 2010–2021. [a]

Capacities in barrels per calendar day (b/cd) from January 1 of each year.

Year	Los Angeles, CA	Martinez, CA	Anacortes, WA	California Subtotal	CA & WA Subtotal
2010	96,860	166,000	120,000	262,860	382,860
2011	94,300	166,000	120,000	260,300	380,300
2012	103,800	166,000	120,000	269,800	389,800
2013	103,800	166,000	120,000	269,800	389,800
2014	355,500	166,000	120,000	521,500	641,500
2015	361,800	166,000	120,000	527,800	647,800
2016	355,170	166,000	120,000	521,170	641,170
2017	364,100	166,000	120,000	530,100	650,100
2018	341,300	166,000	120,000	507,300	627,300
2019	363,000	161,500	119,000	524,500	643,500
2020	363,000	161,000	119,000	524,000	643,000
2021	363,000	—	119,000	363,000	482,000
	Growth in capacity from 2010–2020 in barrels per day:			261,140	260,140
	Growth as a percentage of Martinez capacity on 1/1/20:			162 %	162 %
	Growth in capacity from 2010–2021 in barrels per day:			100,140	99,140

[a] Data from USEIA, 2021. *Capacity Data by Individual Refinery.* (Att. 16).

Since refineries wear out in the absence of sufficient reinvestment,[159] and run more efficiently when running closer to full capacity, those decisions to invest and expand elsewhere set the stage for refining asset consolidation. Its setting, landward of a shallow shipping channel that forces tankers to partially unload, wait for high tide, or both, before calling at Martinez[160] further set up

[156] USEIA, 2015 (Att. 11).
[157] The DEIR baseline analysis does not explicitly blame COVID-19 for the Marathon Martinez crude refinery closure, however, it bears note that the DEIR does not identify any other California refinery that closed during the pandemic, and it appears that this is the only California refinery to close coincident with the pandemic to date.
[158] Marathon Petroleum Corp., 2019 Annual Report, Part I, p. 9 (2019 Annual Report). https://www.annualreports.com/HostedData/AnnualReportArchive/m/NYSE_MPC_2019.pdf.
[159] Karras, 2020 (Att. 10).
[160] ACOE, 2019, Draft Integrated General Reevaluation Report and Environmental Impact Statement, San Francisco Bay to Stockton, California Navigation Study. Army Corps of Engineers: Jacksonville, FL EIS and EIS Appendix D. *See* p. ES-3, maps. Appended hereto as Attachment 30. *See* pp. ES-3, D-22, D-24, maps.

the refinery to close in that consolidation. Indeed, Marathon informed investors that it expected to complete the "consolidation" and expansion of its refining facilities in Los Angeles in the first quarter of 2020,[161] just before it finally closed the refinery in April. In fact, closing the refinery lets Marathon run its Los Angeles and Anacortes refineries closer to full. <u>*See*</u> § 5.2.2.

The sequence of events further links crude refining closure at Martinez to consolidation and not to the project. The refining assets consolidation began years ago, before Marathon owned those assets, and its Los Angeles refinery expansion component appeared to be complete before early 2020 (Table 9), when its CEO expected to complete the consolidation.[162] Marathon shut down crude refining at Martinez in April 2020 (§ 5.1.2). Then, and only after that shutdown, Marathon launched this project (§ 5.1.3). Timing links the shutdown to consolidation, not to the project.

5.2.2 <u>Closing the crude refinery relieved a pre-existing condition of serious and growing petroleum refining structural overcapacity in California and on the West Coast</u>

The DEIR baseline analysis does not consider available evidence that, instead of its unsupported choice between only the project and onsite crude refining, the true alternative to the project may be refinery decommissioning. Crude refineries in this fuels market have long been overbuilt and, for more than a decade as demand for petroleum fuels declined in their domestic markets, have exported large and growing volumes of their petroleum fuels production to more distant markets where their exports command lower prices.[163] But even with those exports, and even during the recent strong petroleum fuels demand surge in their domestic markets, California and West Coast refineries continued to run well below capacity. § 2.2. Idle California refining capacity during the recent demand surge exceeded the former capacity of the Martinez refinery and approached the Marathon Los Angeles refinery capacity (§ 2.2; Table 5, Table 9).

The growing structural overcapacity that idled up to 305,000 b/d of refining capacity during the recent fuels demand surge in California could have idled 466,000 b/d, had Marathon not closed its Martinez refinery (§ 2.2; Table 5, Table 9). Marathon had recently expanded its West Coast capacity so much that it was left with more refining capacity after closing Martinez than it had before its Los Angeles capacity expansion began. Table 9. The refiner then faced a choice

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[161] 2019 Annual Report. <u>*See*</u> "From the Chairman and CEO" at p. 1.
[162] *Id.*
[163] <u>*See*</u> § 2.2 herein; <u>*see*</u> also Karras, 2020 (Att. 10).

between spending more on three refineries running closer to empty and spending less on two refineries running closer to full—with essentially equivalent domestic market share and declining demand. Two refineries closer to full could be more profitable. Marathon shuttered the Martinez crude refining operations. That relieved a growing overcapacity cost.

Moreover, if Marathon still found crude refining at Martinez profitable there was no reason for it to shut that off before project construction. Phillips 66, for example, is refining crude in Rodeo while it seeks approval for its Rodeo biofuel plans, and proposes to refine still more crude there while rebuilding for biofuel refining.[164] The DEIR does not explain its conclusion that crude refining will occur here without the project when it has not occurred here since April 2020.

5.2.3 <u>The crude refinery stayed closed when statewide fuels refining began to rebound in 2020</u>

Through the summer of 2020 statewide refinery engine fuels production began a partial rebound. From its deeply cut late-April 2020 low, combined refinery gasoline, distillate and jet fuel yield statewide rose 26% by the first week of June, 27% by the first week of July, 32% by the second week of August, then 36% and 39% by the first and last weeks of September, respectively.[165] Marathon did not restart crude refining in Martinez, instead announcing in July 2020 that it has no plans to restart the refinery. § 5.1.2.

5.2.4 <u>Marathon did not restart the crude refinery when petroleum fuels demand rebounded to approach and then reach pre-COVID levels from April through July of 2021</u>

By July 2021 a strong surge in petroleum fuels demand that started in April reached pre-COVID levels, accounting for seasonal and interannual variability, across California and the West Coast as a whole. § 2.2. Crude refining did not restart at the Martinez refinery during this strong surge in demand, and has not restarted to date. In fact, the actions taken by Marathon before and since the company shuttered the crude refinery and its assertion of no plans to restart the crude refinery are consistent with its closure in the refining assets consolidation and with effects of structural overcapacity discussed above. The DEIR does not consider this available evidence suggesting that the Marathon Martinez crude refinery will not restart.

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[164] County File No. CDLP20-02040.
[165] CEC *Fuel Watch* (Att. 13).

5.3 The DEIR Does Not Evaluate Technological, Energy Policy, or Climate Policy Factors That Further Suggest Re-establishment of Crude Refining Operations at the Project Site is Unlikely Whether or Not the Project Proceeds

5.3.1 Battery-electric vehicles growth would worsen petroleum refining overcapacity

A superior technology has emerged that is very likely to replace internal combustion engine (ICE) vehicles, reducing demand for combustion fuels, worsening refining overcapacity, and greatly increasing the implausibility of resuming historic Martinez crude refining operations. Going roughly three times as far per unit energy with fewer moving parts to wear and replace, battery-electric vehicle (BEV) technology has—or will soon have—lower total car ownership cost than ICE technology.[166] U.S. and foreign automakers report investments in production of lower sticker-price BEVs. The DEIR does not evaluate BEV effects on refinery restart.

Charging infrastructure buildout[167] and the balance of post-tax public subsidies to BEV *versus* ICE technology appear relevant to how quickly the postulated refinery restart could become clearly implausible, as discussed in § 5.3.3.

5.3.2 State energy and climate policies could worsen petroleum refining overcapacity

California climate and energy policies have converged on broad goals to replace ICE vehicles with zero-emission vehicles (ZEVs) while dramatically expanding solar, wind, and electrolytic hydrogen fuel infrastructure for those ZEVs—BEVs and fuel cell-electric vehicles.[168] Cuts in gasoline-powered transport of roughly 90% by 2045 are targeted along with near-100% renewable electricity as essential to climate stabilization by state-sponsored planning research toward these goals.[169] This would reduce refined fuels demand and hence the plausibility of refinery restart. How much, and how quickly, may depend in large part on local land use commitments to zero-emission infrastructure, however.[170] The DEIR baseline analysis does not consider effects of state ZEV plans or local siting actions on refinery restart.

5.3.3 Mutually reinforcing technology and policy factors suggest refinery restart is unlikely

The future remains uncertain—as the DEIR examples by assuming future uses of the project site could only be for the project or crude refining—and still, a general observation can be drawn

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166 Karras, 2021a (Att. 2).
167 *Id.*
168 *Id.*
169 *Id.*
170 *See* Karras, 2020 (Att. 10).

from the information reported in subsections 5.3.1 and 5.3.2. Interactions, however imperfect, between the capability of BEV technology to replace petroleum, state capabilities to support its ZEVs goal, and local capabilities to site and host appropriate and desirable land uses would tend to accelerate replacement of ICE with BEV vehicles.

For example, the state might subsidize buildout of charging infrastructure, enabling more people to use BEVs, who may in turn support siting more charging infrastructure in their communities.

Relevant to the DEIR baseline analysis, these mutually reinforcing technology and policy factors will likely work together to reduce future petroleum fuels demand more quickly than either factor would reduce it alone, thereby decreasing the plausibility of future crude refining restart. The DEIR does not consider these relevant factors in its baseline analysis.

CONCLUSION: The DEIR baseline conclusion, that petroleum refining would restart onsite in the future if the proposed project does not proceed, fails to represent existing conditions and is speculative, unsupported by facts in the DEIR and rebutted by available evidence that the DEIR does not disclose or evaluate. The use of this inflated baseline in the DEIR was an error that obscured the significance of project impacts and resulted in a deficient impacts evaluation.

CONCLUSIONS

1. The DEIR provides an incomplete, inaccurate, and truncated or at best unstable description of the proposed project. Available information that the DEIR does not describe or disclose will be necessary for sufficient review of environmental impacts that could result from the project.

2. A reasonable potential exists for the project to result in significant climate and air quality impacts by increasing the production and export of California-refined fuels instead of replacing petroleum fuels. This impact would be related to the particular type and use of biofuel proposed. Resultant greenhouse gases and co-pollutants would emit in California from excess petroleum and biofuel refining, and emit in California as well as in other states and nations from petroleum and biofuel feedstock extraction and end-use fuel combustion. The DEIR does not identify, evaluate, or mitigate these significant potential impacts of the project.

3. There is a reasonable potential for the proposed changes in refinery feedstock processing to result in specific hazard impacts involving hydro-conversion processing, including explosion and uncontrolled refinery fire, in excess of those associated with historic petroleum crude refining operations. The DEIR did not identify, evaluate, or mitigate these significant process hazard impacts that could result from the project.

4. The project is likely to result in a significant air quality impact associated with flaring, and has reasonable potential to worsen this impact compared with historic petroleum crude refining operations at the site. The DEIR does not identify, evaluate, or analyze measures to lessen or avoid, this significant potential impact.

5. The DEIR baseline conclusion, that petroleum refining would restart onsite in the future if the proposed project does not proceed, fails to represent existing conditions and is speculative, unsupported by facts in the DEIR and rebutted by available evidence that the DEIR does not disclose or evaluate. The use of this inflated baseline in the DEIR was an error that obscured the significance of project impacts and resulted in a deficient impacts evaluation.

Attachments List

1. Curriculum Vitae and Publications List

2. Karras, 2021a. *Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing;* prepared for the Natural Resources Defense Council (NRDC) by Greg Karras, G. Karras Consulting. August 2021.

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4. USDOE, 2021. *Renewable Hydrocarbon Biofuels;* U.S. Department of Energy, accessed 29 Nov 2021 at https://afdc.energy.gov/fuels/emerging_hydrocarbon.html

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14. CARB GHG Inventory. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity; 14th ed.: 2000 to 2019;* California Air Resources Board: Sacramento, CA. https://ww2.arb.ca.gov/ghg-inventory-data

15. CDTFA, various years. *Fuel Taxes Statistics & Reports;* California Department of Tax and Fee Administration: Sacramento, CA. https://www.cdtfa.ca.gov/taxes-and-fees/spftrpts.htm.

16. USEIA *Refinery Capacity by Individual Refinery*. Data as of January 1, 2021; U.S. Energy Information Administration: Washington, D.C. www.eia.gov/petroleum/refinerycapacity

17. USEIA *Refinery Utilization and Capacity*. PADD 5 data as of Sep 2021. U.S. Energy Inf. Administration: Washington, D.C. www.eia.gov/dnav/pet/pet_pnp_unc_dcu_r50_m.htm 18. Pearlson et al., 2013. A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production. *Biofuels, Bioprod. Bioref.* 7: 89–96. DOI: 10.1002/bbb.1378.

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28. Ezersky, 2006. *Staff Report: Proposed Amendments to Regulation 12, Miscellaneous Standards of Performance, Rule 12, Flares at Petroleum Refineries;* 3 March 2006. Planning and

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